Exhibit A

Proposed Reliability Standards TOP-001-2, TOP-002-3, TOP-003-2, PRC-001-2

A. Introduction

1. **Title:** **Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

   4.5. Load-Serving Entity

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning,]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R8. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence that it complied with each Reliability Directive issued and identified as such by the Transmission Operator(s) unless such action would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M2. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified, Reliability Directive(s) issued in accordance with Requirement R2. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M3. Each Transmission Operator shall make available, upon request, evidence that it has informed its Reliability Coordinator and Transmission Operators that it knew or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M4. Each Transmission Operator shall make available, upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4, unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M5. Each Transmission Operator shall make available, upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5, unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M6. Each Balancing Authority and Transmission Operator shall make available, upon request, evidence that it notified its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Balancing Authority or Transmission Operator may provide an attestation that an event has not occurred.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include, but is not limited to, an electronic or hard copy of information from the Operational Planning Analysis used in its assessment, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based, as specified in Requirement R8 and in Requirement R9. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8, in accordance with Requirement R11. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, and such action would not have violated safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
For the Requirement R3, R5, R6, and R8 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting

	Lower	Moderate	High	Severe
				entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R5	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform its Reliability Coordinator of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
R6	The responsible entity did not notify one negatively-impacted interconnected NERC-registered entity, or 5% or less of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively-impacted interconnected NERC-registered entities, or more than 5% and less than or equal to 10% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify three negatively-impacted interconnected NERC-registered entities, or more than 10% and less than or equal to 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more negatively-impacted interconnected NERC-registered entities, or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and

	Lower	Moderate	High	Severe
				control equipment and associated communication channels between the affected entities.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of two SOLs, or more than 5% and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of three SOLs, or more than 10% and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs, or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL), as identified in Requirement R8, for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, had been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act, or direct others to act, to mitigate both the magnitude and duration of

	Lower	Moderate	High	Severe
				exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	May 9, 2012	Adopted by Board of Trustees; Revisions pursuant to Project 2007-03	Revised

A. Introduction

1. Title: ~~**Reliability Responsibilities and Authorities**~~**Transmission Operations**

2. Number: TOP-001-~~1a~~2

~~**Purpose:** To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.~~

3. Purpose: To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

~~3.~~4. Applicability

~~3.1.~~4.1. Balancing ~~Authorities~~Authority

~~3.2.~~4.2. Transmission ~~Operators~~Operator

~~3.3.~~4.3. Generator ~~Operators~~Operator

~~3.4.~~4.4. Distribution ~~Providers~~Provider

~~3.5.~~4.5. Load~~-~~-Serving ~~Entities~~Entity

~~**4. Effective Date:** Immediately after approval of applicable regulatory authorities.~~

5. Effective Date: All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

~~**R1.**~~ Each ~~Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.~~

~~**R2.** Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.~~

~~**R3.** Each Transmission Operator,~~ Balancing Authority, ~~and~~ Generator Operator ~~shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.~~

~~R4.~~R1. ~~Each~~, Distribution Provider, and Load~~-~~-Serving Entity shall comply with ~~all reliability directives~~each Reliability Directive issued and identified as such by ~~the~~its Transmission

Operator~~, including shedding firm load,~~(s), unless such ~~actions~~action would violate safety, equipment, regulatory, or statutory requirements. ~~Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.~~*[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

~~R5.~~R3. Each Transmission Operator shall inform its Reliability Coordinator and ~~any other potentially~~Transmission Operator(s) that are known or expected to be affected ~~Transmission Operators of real time or~~ by each actual and anticipated ~~emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.~~Emergency based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning,]*

~~R6.~~R4. Each Transmission Operator~~, Balancing Authority, and Generator Operator~~ shall render ~~all available~~ emergency assistance to ~~others~~other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, ~~or~~ regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

~~**R7.** Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:~~

~~**R7.1.** For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.~~

R5. ~~For a transmission facility,~~Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator ~~shall notify and coordinate~~

~~Rationale: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised~~

~~with its Reliability Coordinator. The~~as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~R7.2.~~R9. Each Transmission Operator shall ~~notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.~~not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

~~R7.3.~~ ~~When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the~~ Each Transmission Operator~~, and the Transmission Operator~~ shall ~~notify~~inform its Reliability Coordinator ~~and adjacent Transmission Operators, at the earliest possible time.~~

~~R8.~~R10. ~~During a~~ of its actions to return the system ~~emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the~~to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon:* *Real*~~and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.~~*-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

~~M1.~~ Each ~~Transmission Operator~~Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall ~~have and provide~~make available, upon request, evidence that it complied with each Reliability Directive issued and identified as such by the Transmission Operator(s) unless such action would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, ~~signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.~~

~~M2.~~ ~~If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic~~

~~communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)~~

M1. ~~Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as~~dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that ~~will be used~~an event has not occurred.

M2. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence which may include, but is not limited to ~~determine if~~dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it ~~complied with~~informed its ~~Reliability Coordinator's reliability directives. If the~~ Transmission Operator~~, Balancing Authority or Generator Operator did not~~ of its inability to comply with identified, Reliability Directive(s) issued in accordance with Requirement R2. If no event has occurred, the ~~directive because it~~Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M3. Each Transmission Operator shall make available, upon request, evidence that it has informed its Reliability Coordinator and Transmission Operators that it knew or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

~~M3.~~M4. Each Transmission Operator shall make available, upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4, unless such actions would violate safety, equipment, regulatory, or statutory requirements~~, it shall provide~~. Such evidence ~~such as~~could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence ~~that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)~~ in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

~~M4.~~M5. ~~Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent~~Each Transmission Operator shall make available, upon request, evidence that ~~will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as~~it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission

Operator Areas in accordance with Requirement R5, unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence ~~that it immediately informed~~. If no event has occurred, the Transmission Operator ~~of its inability to perform the directive. (Requirements 3 and 4)~~may provide an attestation that an event has not occurred.

~~M5.~~M6. ~~The~~ Each Balancing Authority and Transmission Operator shall ~~have and provide~~make available, upon request, evidence that it notified its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Balancing Authority or Transmission Operator may provide an attestation that ~~will be used to determine if it informed its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)~~an event has not occurred.

M7. ~~The~~Each Transmission Operator~~, Balancing Authority, and Generator Operator~~ shall ~~each have and provide upon request~~make available evidence ~~that~~ for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

~~M6.~~M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include, but is not limited to, an electronic or hard copy of information from the Operational Planning Analysis used in its assessment, dated operator logs, voice recordings or transcripts of voice recordings, ~~electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided~~or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that ~~the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)~~an event has not occurred.

M9. ~~The~~Each Transmission ~~Operator and Generator~~ Operator shall ~~each have and provide upon request evidence~~make available evidence for any occasion in which it has operated outside an SOL for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based, as specified in Requirement R8 and in Requirement R9. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

~~M7.~~**M11.** Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8, in accordance with Requirement R11. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, ~~electronic communications, or other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)~~or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

- For entities that do not work for the Regional ~~Reliability Organizations~~Entity, the Regional Entity shall ~~be responsible for compliance monitoring~~serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and ~~Reset Time Frame~~Enforcement Processes

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

~~Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)~~

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall ~~keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.~~

~~Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.~~

~~Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3~~retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and ~~4.~~

~~Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4~~its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If ~~an entity is~~ a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant ~~the entity~~, it shall keep information related to the ~~noncompliance~~non-compliance until ~~found compliant or for two years plus the current year~~mitigation is complete and approved or the time period specified above, whichever is longer.

~~Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,~~

The Compliance ~~Monitor~~Enforcement Authority shall keep the last ~~periodic~~ audit ~~report~~records and all ~~supporting compliance data~~requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels ~~of Non-Compliance for a Balancing Authority:~~

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2:** Not applicable.~~

~~**2.3. Level 3:** Not applicable.~~

~~**2.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**2.4.1** Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)~~

~~**2.4.2** Did not render emergency assistance to others as requested, in accordance with R6.~~

~~**3. Levels of Non-Compliance for a Transmission Operator**~~

~~**3.1. Level 1:** Not applicable.~~

~~**3.2. Level 2:** Not applicable.~~

~~**3.3. Level 3:** Not applicable.~~

~~**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**3.4.1** Does not have the documented authority to act as specified in R1.~~

~~**3.4.2** Does not have evidence it acted with the authority specified in R1.~~

~~**3.4.3** Did not take immediate actions to alleviate operating emergencies as specified in R2.~~

~~**3.4.4** Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.~~

~~**3.4.5** Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.~~

~~**3.4.6** Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.~~

~~**3.4.7** Did not render emergency assistance to others as requested, as specified in R6.~~

~~**3.4.8** Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.~~

~~**4. Levels of Non-Compliance for a Generator Operator:**~~

~~**4.1. Level 1:** Not applicable.~~

~~**4.2. Level 2:** Not applicable.~~

~~**4.3. Level 3:** Not applicable.~~

~~**4.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**4.4.1** Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.~~

~~**4.4.2** Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.~~

~~**4.4.3** Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.~~

~~**5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity**~~

~~**5.1. Level 1:** Not applicable.~~

~~**5.2. Level 2:** Not applicable.~~

~~**5.3. Level 3:** Not applicable~~

~~**5.4. Level 4:** Did not comply with a Transmission Operator's reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.~~

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, and such action would not have violated safety, equipment, regulatory,

	Lower	Moderate	High	Severe
				or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
For the Requirement R3, R5, R6, and R8 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R5	The Transmission Operator did not	The Transmission Operator did not	The Transmission Operator did not	The Transmission Operator did not

	Lower	Moderate	High	Severe
	inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	inform its Reliability Coordinator of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
R6	The responsible entity did not notify one negatively-impacted interconnected NERC-registered entity, or 5% or less of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively-impacted interconnected NERC-registered entities, or more than 5% and less than or equal to 10% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify three negatively-impacted interconnected NERC-registered entities, or more than 10% and less than or equal to 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more negatively-impacted interconnected NERC-registered entities, or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and control equipment and associated communication channels between the affected entities.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a

	Lower	Moderate	High	Severe
				continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of two SOLs, or more than 5% and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of three SOLs, or more than 10% and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs, or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL), as identified in Requirement R8, for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, had been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.

E. Regional ~~Differences~~Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
~~1a~~2	May ~~12, 2010~~9, 2012	~~Added Appendix 1 – Interpretation of R8 approved by BOT on May 12, 2010~~Adopted by Board of Trustees; Revisions pursuant to Project 2007-03	~~Interpretation~~Revised
~~1a~~	~~September 15, 2011~~	~~FERC Order issued approved the Interpretation of R8 (FERC Order became effective November 21, 2011)~~	~~Interpretation~~

~~Appendix 1~~

~~Requirement Number and Text of Requirement~~
~~**R8**. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.~~
~~Question~~
~~For Requirement R8 is the Balancing Authority responsibility to immediately take corrective action to restore Real Power Balance and is the TOP responsibility to immediately take corrective action to restore Reactive Power Balance?~~
~~Response~~
~~The answer to both questions is yes. According to the NERC *Glossary of Terms Used in Reliability Standards*, the Transmission Operator is responsible for the reliability of its “local” transmission system, and operates or directs the operations of the transmission facilities. Similarly, the Balancing Authority is responsible for maintaining load-interchange-generation balance, i.e., real power balance. In the context of this requirement, the Transmission Operator is the functional entity that balances reactive power. Reactive power balancing can be accomplished by issuing instructions to the Balancing Authority or Generator Operators to alter reactive power injection. Based on NERC Reliability Standard BAL-005-1b Requirement R6, the Transmission Operator has no requirement to compute an Area Control Error (ACE) signal or to balance real power. Based on NERC Reliability Standard VAR-001-1 Requirement R8, the Balancing Authority is not required to resolve reactive power balance issues. According to TOP-001-1 Requirement R3, the Balancing Authority is only required to comply with Transmission Operator or Reliability Coordinator instructions to change injections of reactive power.~~

A. Introduction

1. **Title:** **Operations Planning**
2. **Number:** TOP-002-3
3. **Purpose:** To ensure that Transmission Operators have plans for operating within specified limits.
4. **Applicability**

   4.1. Transmission Operator.
5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include, but is not limited to, dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include, but it is not limited to, plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement for a rolling six-month period for analyses, the most recent 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

<table>
<tr><th>R#</th><th>Lower</th><th>Moderate</th><th>High</th><th>Severe</th></tr>
<tr><td>R1</td><td>N/A</td><td>N/A</td><td>N/A</td><td>The Transmission Operator did not have an Operational Planning Analysis that represented projected System conditions allowing it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.</td></tr>
<tr><td>R2</td><td>N/A</td><td>N/A</td><td>N/A</td><td>The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.</td></tr>
<tr><td colspan="5">For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.</td></tr>
<tr><td>R3</td><td>The Transmission Operator did not notify one NERC-registered entity, or 5% or less of the</td><td>The Transmission Operator did not notify two NERC-registered entities, or more than 5%, and</td><td>The Transmission Operator did not notify three NERC-registered entities, or more than 10% and</td><td>The Transmission Operator did not notify four or more NERC-registered entities, or more</td></tr>
</table>

	NERC-registered entities, whichever is less identified in the plan(s) cited, as to their role in the plan(s).	less than or equal to 10% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	less than or equal to 15% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	than15% of the NERC-registered entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	May 9, 2012	Changes pursuant to Project 2007-03	Revised
3	May 9, 2012	Adopted by Board of Trustees	

A. Introduction

1. **Title:** ~~Normal~~ **Operations Planning** ~~—~~

2. **Number:** TOP-002-~~2b~~3

3. **Purpose:** ~~Current operations~~To ensure that Transmission Operators have plans ~~and procedures are essential to being prepared~~ for ~~reliable operations, including response for unplanned events~~operating within specified limits.

4. **Applicability**

   ~~**4.1.** Balancing Authority.~~

   ~~**4.2.**~~**4.1.** Transmission Operator.

   ~~**4.3.** Generator Operator.~~

   ~~**4.4.** Load Serving Entity.~~

   ~~**4.5.** Transmission Service Provider.~~

~~**5. Effective Date:** Immediately after approval of applicable regulatory authorities. FERC Approved 12/2/09~~

5. Effective Date: All requirements will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption.

B. Requirements

R1. Each ~~Balancing Authority and~~ Transmission Operator shall ~~maintain a set of current plans~~have an Operational Planning Analysis that ~~are designed~~represents projected System conditions that will allow it to ~~evaluate options and set procedures~~ assess whether the planned operations for ~~reliable operation through a reasonable future time period. In addition, each Balancing Authority and~~ the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**R1.**~~**R2.** Each Transmission Operator shall ~~be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.~~develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**R2.**~~ Each ~~Balancing Authority and~~ Transmission Operator shall ~~ensure its operating personnel participate~~notify all NERC registered entities identified in the ~~system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.~~

~~**R3.** Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission~~

~~Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.~~

~~**R4.** Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed~~plan(s) cited in ~~an orderly and consistent manner.~~

~~**R5.** Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.~~

~~**R6.** Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.~~

~~**R7.** Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.~~

~~**R8.** Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.~~

~~**R9.** Each Balancing Authority shall plan to meet Interchange Schedules and ramps.~~

~~**R10.** Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).~~

~~**R11.** The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies~~Requirement R2 as ~~necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.~~

~~**R12.** The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.~~

~~**R13.** At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.~~

~~**R14.**~~**R3.** ~~Generator Operators shall, without any intentional time delay, notify~~ to their ~~Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:~~role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**R14.1.** Changes in real and reactive output capabilities. (Retired August 1, 2007)~~

~~**R14.1.** Changes in real output capabilities. (Effective August 1, 2007)~~

~~**R14.2.** Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)~~

~~**R15.** Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).~~

~~**R16.** Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:~~

~~**R16.1.** Changes in transmission facility status.~~

~~**R16.2.** Changes in transmission facility rating.~~

~~**R17.** Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.~~

~~**R18.** Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.~~

~~**R19.** Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.~~

C. Measures

M1. Each ~~Balancing Authority and~~ Transmission Operator shall have ~~and provide upon request~~ evidence ~~that~~ of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include, but is not limited to, ~~documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).~~dated power flow study results.

M2. Each ~~Balancing Authority and~~ Transmission Operator shall have ~~and provide upon request~~ evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include, but it is not limited to, ~~copies~~plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of ~~current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10~~the Operational Planning Analysis.

~~**M3.**~~ Each ~~Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.~~

~~**M4.** Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)~~

~~**M5.**~~**M3.** ~~Each~~ Transmission Operator shall have ~~and provide upon request evidence that could include,~~evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings ~~or~~

~~transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)~~, or e-mail records.

~~**M6.** Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.~~

~~**M7.** Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)~~

~~**M8.** Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)~~

~~**M9.** Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)~~

~~**M10.** Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~Regional Reliability Organizations shall be responsible for compliance monitoring.~~

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and ~~Reset Time Frame~~Enforcement Processes

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~

- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3. Data Retention

~~For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).~~

~~For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).~~

~~For Measure 4, each~~The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator shall keep ~~its current plans (evidence).~~

~~For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).~~

~~For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).~~

~~For Measure 10, each Balancing~~data or evidence to show compliance for each Requirement for a rolling six-month period for analyses, the most recent 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records, unless directed by its Compliance Enforcement Authority~~, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent~~ to retain specific evidence ~~as evidence~~for a longer period of time as part of an investigation.

If ~~an entity~~a Transmission Operator is found non-compliant~~ the entity~~, it shall keep information related to the ~~noncompliance~~non-compliance until found compliant or ~~for two years plus the current year~~the time period specified above, whichever is longer.

~~Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,~~

The Compliance ~~Monitor~~Enforcement Authority shall keep the last ~~periodic~~ audit ~~report~~records and all ~~supporting compliance data~~requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels ~~of Non-Compliance for Balancing Authorities:~~

~~**2.1. Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.~~

~~**2.2. Level 2:** Not applicable.~~

~~**2.3. Level 3:** Not applicable.~~

~~**2.4. Level 4**: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**2.4.1** Did not maintain an updated set of current-day plans as specified in R1.~~

~~**2.4.2** Plans did not meet one or more of the requirements specified in R5 through R10.~~

~~**3. Levels of Non-Compliance for Transmission Operators**~~

~~**3.1. Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.~~

~~**3.2. Level 2:** Not applicable.~~

~~**3.3. Level 3:** One or more of Bulk Electric System studies were not made available as specified in R11.~~

~~**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**3.4.1** Did not maintain an updated set of current-day plans as specified in R1.~~

~~**3.4.2** Plans did not meet one or more of the requirements in R5, R6, and R10.~~

~~**3.4.3** Studies not updated to reflect current system conditions as specified in R11.~~

~~**3.4.4** Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.~~

~~**4. Levels of Non-Compliance for Generator Operators:**~~

~~**4.1. Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.~~

~~**4.2. Level 2:** Not applicable.~~

~~**4.3. Level 3:** Not applicable.~~

~~**4.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**4.4.1** Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.~~

~~**4.4.2** Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.~~

~~**4.4.3** Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.~~

~~**5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:**~~

~~**5.1. Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.~~

~~**5.2. Level 2:** Not applicable.~~

~~**5.3. Level 3:** Not applicable.~~

~~**5.4. Level 4:** Not applicable.~~

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis that represented projected System conditions allowing it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the

				Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one NERC-registered entity, or 5% or less of the NERC-registered entities, whichever is less identified in the plan(s) cited, as to their role in the plan(s).	The Transmission Operator did not notify two NERC-registered entities, or more than 5%, and less than or equal to 10% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three NERC-registered entities, or more than 10% and less than or equal to 15% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more NERC-registered entities, or more than15% of the NERC-registered entities identified in the plan(s) as to their role in the plan(s).

E. Regional ~~Differences~~Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	~~June 14, 2007~~May 9, 2012	~~Fixed typo in R11., (subject to …)~~Changes pursuant to Project 2007-03	~~Errata~~Revised
~~2a~~	~~February 10, 2009~~	~~Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009~~	~~Interpretation~~
~~2a~~	~~December 2, 2009~~	~~Interpretation of R11 approved by FERC on December 2, 2009~~	~~Same Interpretation~~
~~2b~~3	~~November 4, 2010~~May 9, 2012	~~Added Appendix 2 – Interpretation of R10 adopted~~Adopted by ~~the~~ Board of Trustees	
~~2b~~	~~October 20, 2011~~	~~FERC Order issued approving the Interpretation of R10 (FERC's Order became effective on October 20, 2011)~~	

~~Appendix 1~~

~~Interpretation of Requirement R11~~

~~Requirement Number and Text of Requirement~~

~~Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.~~

~~Question #1~~
~~Is the Transmission Operator required to conduct a "unique" study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?~~

~~Response to Question #1~~
~~Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have "a" study that can be applied to it, but it is not necessary to generate a "unique" study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.~~

~~Question #2~~
~~Are there specific actions required to implement a "study"? In other words, what constitutes a study?~~

~~Response to Question #2~~
~~The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.~~

~~Question #3~~
~~Does the term, "to determine SOLs" as used in the first sentence of Requirement R11 mean the "determination of system operating limits" or does it mean the "identification of potential SOL violations?"~~

~~Response to Question #3~~
~~TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential "exceedances" of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.~~

~~**Appendix 2**~~

~~**Requirement Number and Text of Requirement:**~~

~~R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).~~

~~**Clarification needed:**~~

~~Requirement 10 is proposed to be eliminated in Project 2007-03 because it is redundant with TOP-004-0 R1, which only applies to TOP not to BA. However, that will not be effective for more than two years. In the meantime, in Requirement 10 is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?~~

~~Project 2009-27: Response to Request for an Interpretation of TOP-002-2a, Requirement R10, for Florida Municipal Power Pool~~
~~The following interpretation of TOP-002-2a — Normal Operations Planning, Requirement R10, was developed by the Real-time Operations Standard Drafting Team.~~
~~**Requirement Number and Text of Requirement**~~
~~**R10.** Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).~~
~~**Question**~~
~~In Requirement 10, is the requirement of the BA to plan to maintain load-interchange-generation balance under the direction of the TOPs meeting all SOLs and IROLs?~~
~~**Response**~~
~~Yes. As stated in the NERC *Glossary of Terms used in Reliability Standards*, the Balancing Authority is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area, and supporting Interconnection frequency in real time. The Balancing Authority does not possess the Bulk Electric System information necessary to manage transmission flows (MW, MVAR or Ampere) or voltage. Therefore, the Balancing Authority must follow the directions of the Transmission Operator to meet all SOLs and IROLs.~~

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their operational planning and Real-time monitoring responsibilities.

4. **Applicability**

   4.1. Transmission Operator.

   4.2. Balancing Authority.

   4.3. Generator Owner.

   4.4. Generator Operator.

   4.5. Interchange Authority.

   4.6. Load-Serving Entity.

   4.7. Transmission Owner.

   4.8. Distribution Provider.

5. **Effective Date:** All requirements, except Requirement R5, will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements, except Requirement R5, become effective the first day of the first calendar quarter ten months following Board of Trustees' adoption. Requirement R5 will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R5 becomes effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

1.2. A mutually-agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. A mutually-agreeable format.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

R3. Each Transmission Operator shall distribute its data specification, as developed in Requirement R1,to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority shall distribute its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall make available its dated, current, in-force documented specification for data in accordance with Requirement R1.

M2. Each Balancing Authority shall make available its dated, current, in-force documented specification for data in accordance with Requirement R2.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification, as developed in Requirement R1, to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their Operational Planning Analyses and Real-time monitoring, in accordance with Requirement R1 and Measurement M1, as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their analysis functions and Real-time monitoring, in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R1 to entities that have data required by the Transmission Operator’s Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority’s analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90 calendar days that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.
R2	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring. OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring	The Transmission Operator did not distribute its data specification, as developed in requirement R1 to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring

	process used in meeting its NERC-mandated reliability requirements.	Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	process used in meeting its NERC-mandated reliability requirements.
For the Requirement R4 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R4	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements .	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to four or more entities, or more than 15% of the entities, whichever is less,that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.
R5	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

E. **Regional Variances**
None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	May 9, 2012	Changes pursuant to Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	

A. Introduction

1. **Title:** ~~**Planned Outage Coordination**~~**Operational Reliability Data**

2. **Number:** TOP-003-~~1~~2

3. **Purpose:** ~~Scheduled generator and transmission outages~~To ensure that ~~may affect~~ the ~~reliability of interconnected operations must be planned and coordinated among Balancing Authorities,~~ Transmission ~~Operators, and Reliability Coordinators~~Operator and Balancing Authority have the data needed to fulfill their operational planning and Real-time monitoring responsibilities.

4. **Applicability**

~~**4.1.** Generator Operators.~~

~~**4.2.**~~**4.1.** Transmission ~~Operators~~Operator.

~~**4.3.**~~**4.2.** Balancing ~~Authorities~~Authority.

~~**4.4.** Reliability Coordinators.~~

4.3. ~~**Proposed**~~ Generator Owner.

4.4. Generator Operator.

4.5. Interchange Authority.

4.6. Load-Serving Entity.

4.7. Transmission Owner.

4.8. Distribution Provider.

~~5.~~ **Effective Date:**

~~In those jurisdictions where no regulatory approval is required, the standard shall~~All requirements, except Requirement R5, will become effective ~~on the latter of either April 1, 2009 or~~ the first day of the first calendar quarter~~, three~~ ten months ~~after BOT adoption.~~

5. following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the ~~standard shall~~requirements, except Requirement R5, become effective ~~on the latter of either April 1, 2009 or~~the first day of the first calendar quarter ten months following Board of Trustees' adoption. Requirement R5 will become effective the first day of the first calendar quarter~~, three~~ twelve months ~~after~~following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R5 becomes effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

~~**R1.** Generator Operators and~~ Each Transmission ~~Operators shall provide planned outage information.~~

~~**R1.1.**~~**R1.** ~~Each Generator~~ Operator shall ~~provide outage information daily to its Transmission Operator for scheduled generator outages planned~~create a documented specification for the ~~next day (any foreseen outage of a generator greater than 50 MW).~~data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The ~~Transmission Operator shall establish the outage reporting requirements.~~specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

~~**1.2.** Each Transmission Operator shall provide outage information daily to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.~~

1.1. ~~Such information shall be available by 1200 Central Standard Time for~~ A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

1.2. A mutually-agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the ~~Eastern Interconnection and 1200 Pacific Standard Time~~ indicated data.

R2. Each Balancing Authority shall create a documented specification for the ~~Western Interconnection~~data necessary for it to perform its analysis functions and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. A mutually-agreeable format.

2.3. A periodicity for providing data.

~~**R1.3.**~~**2.4.** The deadline by which the respondent is to provide the indicated data.

~~**R2.**~~**R3.** Each Transmission Operator~~, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.~~ shall distribute its data specification, as developed in Requirement R1,to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority shall distribute its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

~~**R3.**~~ Each Transmission Operator, Balancing Authority, ~~and~~ Generator Owner, Generator Operator ~~shall plan~~, Interchange Authority, Load-Serving Entity, Transmission Owner, and ~~coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.~~

~~**R4.**~~**R5.** ~~Each Reliability Coordinator~~Distribution Provider receiving a data specification in Requirement R3 or R4 shall ~~resolve any scheduling of potential reliability conflicts.~~satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

~~**M1.** Evidence that the Generator Operator, Transmission Operator, and Balancing Authority reported and coordinated scheduled outage information as indicated in the requirements above.~~

M1. Each Transmission Operator shall make available its dated, current, in-force documented specification for data in accordance with Requirement R1.

M2. Each Balancing Authority shall make available its dated, current, in-force documented specification for data in accordance with Requirement R2.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification, as developed in Requirement R1, to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

D. Compliance

1. Compliance Monitoring Process

~~Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.~~

~~Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.~~

1.1. Compliance Monitoring ~~Responsibility~~Process

- ~~A Reliability Coordinator makes a request~~For entities that do not work for ~~an outage to "not be taken" because of a reliability impact on the grid and the outage is still taken. The Reliability~~

~~Coordinator must provide all its documentation within three business days to the~~ the Regional ~~Reliability Organization. Each~~ Entity, the Regional ~~Reliability Organization~~Entity shall ~~report compliance and violations to NERC via the NERC~~ serve as the Compliance ~~Reporting process~~Enforcement Authority.

- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring ~~Period~~ and ~~Reset Timeframe~~Enforcement Processes

~~One calendar year without a violation from the time of the violation.~~

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

~~One calendar year.~~

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their Operational Planning Analyses and Real-time monitoring, in accordance with Requirement R1 and Measurement M1, as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their analysis functions and Real-time monitoring, in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R1 to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R2 to entities that

have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90 calendar days that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

~~Not specified.~~

None

2. Violation Severity Levels~~:~~

~~R#~~	Lower	Moderate	High	Severe
R1	~~N/A~~The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	~~N/A~~The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	~~N/A~~The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring.	~~The Generator Operator failed to provide outage information, in accordance with its Transmission Operators established outage reporting requirements, to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW).~~The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.
~~R1.1~~R2	~~N/A~~The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	~~N/A~~The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	~~N/A~~The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring.	~~The Transmission Operator failed to provide outage information, in accordance with its Reliability Coordinators established outage reporting requirement, to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.~~The Balancing Authority did not include four of

				the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring. OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
~~R1.2~~	~~The responsible entity failed to provide the information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.~~For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.		~~N/A~~	~~N/A~~ ~~N/A~~
~~R1.3~~R3	~~N/A~~The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	~~N/A~~The Transmission Operator did not distribute its data specification, as developed in requirement R1 to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	~~N/A~~The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability	~~The responsible entity failed to plan or coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators when required.~~The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.

			requirements.	
~~R2~~	~~The responsible entity planned and coordinated scheduled outages of telemetering and control equipment and associated communication channels with its Reliability Coordinator, but failed to coordinate with affected neighboring Transmission Operators, Balancing Authorities, and Generator Operators.~~For the Requirement R4 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.		~~N/A~~	~~N/A~~ ~~The responsible entity failed to plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.~~
~~R3~~**R4**	~~N/A~~The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	~~N/A~~The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	~~N/A~~The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements .	~~The Reliability Coordinator failed to resolve any scheduling of potential reliability conflicts.~~The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to four or more entities, or more than 15% of the entities, whichever is less,that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.
~~R4~~**R5**	~~The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to~~	~~The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 35 minutes but less than or equal to 40 minutes.~~N/A	~~The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined),~~	~~The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 45 minutes.~~The responsible entity receiving

	~~restore operations to respect proven reliable power system limits for more than 30 minutes but less than or equal to 35 minutes.~~N/A		~~failed to restore operations to respect proven reliable power system limits for more than 40 minutes but less than or equal to 45 minutes.~~N/A	a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

E. **Regional Variances**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	May 9, 2012	~~Modified R1.2~~ ~~Modified M1~~ ~~Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)~~Changes pursuant to Project 2007-03	Revised
~~1~~2	~~October 17, 2008~~May 9, 2012	Adopted by ~~NERC~~ Board of Trustees	
~~1~~	~~March 17, 2011~~	~~Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)~~	

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-2

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area. *[Violation Risk factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R2.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R2.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R3. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 2, 2.1, and 2.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall be responsible for compliance monitoring.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

If an entity is found non-compliant, the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.3. Compliance Monitoring and Assessment Processes

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Reqmt. #	VRF	Time Horizon	Lower	Moderate	High	Severe
R1	High	Operations Planning, Same-day Operations, Real-time Operations	N/A	N/A	The responsible entity failed to be familiar with the limitations of Protection System schemes applied in its area.	The responsible entity failed to be familiar with the purpose of Protection System schemes applied in its area.
R2	N/A	N/A	N/A	N/A	N/A	N/A
R2.1	High	Operations Planning, Same-day Operations, Real-time Operations	The Generator Operator failed to coordinate one new protective system or protective System change with either its Transmission Operator or its Host Balancing Authority or both.	The Generator Operator failed to coordinate two new protective systems or protective System changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate three new protective systems or protective System changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate more than three new protective systems or protective System changes with its Transmission Operator or its Host Balancing Authority, or both.
R2.2	High	Operations Planning, Same-day Operations, Real-time Operations	The Transmission Operator failed to coordinate one new protective system or protective System change with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate two new protective systems or protective System changes with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate three new protective systems or protective System changes with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate more than three new protective systems or protective System changes with neighboring Transmission Operators or Balancing Authorities, or both.
R3	High	Operations Planning, Same-day	The Transmission Operator failed	The Transmission Operator failed	The Transmission Operator failed	The Transmission Operator failed

		Operations, Real-time Operations	to coordinate Protection Systems on major transmission lines and interconnections with one of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	to coordinate Protection Systems on major transmission lines and interconnections with two of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	to coordinate Protection Systems on major transmission lines and interconnections with three of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	to coordinate Protection Systems on major transmission lines and interconnections with three or more of its neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Delete data requirements as they are now handled in TOP-003-2.	Deleted Requirements 2, 5, and 6.
2	May 9, 2012	Adopted by Board of Trustees	

~~A.~~A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-~~1.1~~2

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** ~~January 1, 2007~~ All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption.

~~C.~~B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of Protection System schemes applied in its area. *[Violation Risk factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~**R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:~~

~~**R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.~~

~~**R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.~~

~~**R3.**~~**R2.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

~~**R3.1.**~~**R2.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~**R3.2.**~~**R2.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~R4.~~R3. Each Transmission Operator shall coordinate Protection Systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~**R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the Protection Systems of others:~~

~~**R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's Protection Systems.~~

~~**R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' Protection Systems.~~

~~**R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.~~

~~D.~~C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements ~~3, 3~~2, 2.1, and ~~3~~2.2.

~~**M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)~~

~~**M3.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)~~

~~E.~~D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

The Regional ~~Reliability Organizations~~Entity shall be responsible for compliance monitoring.

~~**1.2. Compliance Monitoring and Reset Time Frame**~~

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

~~1.3.~~1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

~~Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.~~

If an entity is found non-compliant, the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.3. Compliance Monitoring and Assessment Processes

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the

preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.4. Additional Compliance Information

None.

~~**2. Levels of Non-Compliance for Generator Operators:**~~

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2**: Not applicable.~~

~~**2.3. Level 3**: Not applicable.~~

~~**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.~~

~~**3. Levels of Non-Compliance for Transmission Operators:**~~

~~**3.1. Level 1:** Not applicable.~~

~~**3.2. Level 2**: Not applicable.~~

~~**3.3. Level 3**: Not applicable.~~

~~**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.~~

~~**3.4.2** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

~~**4. Levels of Non-Compliance for Balancing Authorities:**~~

~~**4.1. Level 1:** Not applicable.~~

~~**4.2. Level 2**: Not applicable.~~

~~**4.3. Level 3**: Not applicable.~~

~~**4.4. Level 4:** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

2. Violation Severity Levels

Reqmt. #	VRF	Time Horizon	Lower	Moderate	High	Severe

R1	High	Operations Planning, Same-day Operations, Real-time Operations	N/A	N/A	The responsible entity failed to be familiar with the limitations of Protection System schemes applied in its area.	The responsible entity failed to be familiar with the purpose of Protection System schemes applied in its area.
R2	N/A	N/A	N/A	N/A	N/A	N/A
R2.1	High	Operations Planning, Same-day Operations, Real-time Operations	The Generator Operator failed to coordinate one new protective system or protective System change with either its Transmission Operator or its Host Balancing Authority or both.	The Generator Operator failed to coordinate two new protective systems or protective System changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate three new protective systems or protective System changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate more than three new protective systems or protective System changes with its Transmission Operator or its Host Balancing Authority, or both.
R2.2	High	Operations Planning, Same-day Operations, Real-time Operations	The Transmission Operator failed to coordinate one new protective system or protective System change with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate two new protective systems or protective System changes with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate three new protective systems or protective System changes with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate more than three new protective systems or protective System changes with neighboring Transmission Operators or Balancing Authorities, or both.
R3	High	Operations Planning, Same-day Operations, Real-time	The Transmission Operator failed to coordinate Protection Systems on	The Transmission Operator failed to coordinate Protection Systems on	The Transmission Operator failed to coordinate Protection Systems on	The Transmission Operator failed to coordinate Protection Systems on

		Operations	major transmission lines and interconnections with one of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	major transmission lines and interconnections with two of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	major transmission lines and interconnections with three of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	major transmission lines and interconnections with three or more of its neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

~~F.~~E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Delete data requirements as they are now handled in TOP-003-2.	Deleted Requirements 2, 5, and 6.
~~1.1~~2	~~April 11~~May 9, 2012	~~Errata adopted by the Standards Committee; (Capitalized "Protection System" in accordance with Implementation Plan for Project 2007-17 approval of revised definition of "Protection System")~~Adopted by Board of Trustees	~~Errata associated with Project 2007-17~~

Exhibit B

Order No. 672 Criteria

Exhibit B

Order No. 672 Criteria

In Order No. 672,[30] the Commission identified a number of criteria that it will use to analyze Reliability Standards proposed for approval to ensure that a proposed Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[31] The discussion below identifies these factors, and explains how the proposed TOP Reliability Standards meet or exceed the criteria:[32]

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal**

   Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cyber security protection.

The proposed Reliability Standards each has a specific reliability goal. TOP-001-2 — Transmission Operations, specifically establishes the requirements that describe what a Transmission Operator must do with respect to actual Real-time operations. TOP-002-3 - Operations Planning, specifically describes what a Transmission Operator must do with respect

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[30] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006) (together, "Order 672")).
[31] Section 215(d)(2)(A) of the FPA; 18 C.F.R. §39.5.
[32] Capitalized terms used but not defined in this Attachment A are intended to have the same meaning given to such terms in the Petition, the Proposed Standards or the *Glossary of Terms Used in NERC Reliability Standards*, available at: http://www.nerc.com/files/Glossary_of_Terms.pdf.

to operational planning. TOP-003-2 - Operational Reliability Data specifically describes what the Transmission Operator and Balancing Authority must do to obtain the data it requires.

2. Proposed Reliability Standards must contain a technically sound method to achieve the goal

> Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

The proposed Reliability Standards contain technically sound methods to achieve the goals. The standards describe:

- The need for compliance with Reliability Directives issued by the Transmission Operator (TOP-001-2, Requirement R1).
- Informing the Transmission Operator if an entity can not comply with a Reliability Directive (TOP-001-2, Requirement R2).
- Informing entities of actual and anticipated Emergencies (TOP-001-2, Requirement R3)
- Rendering emergency assistance (TOP-001-2, Requirement R4).
- Informing other entities of operations that may adversely impact them (TOP-001-2, Requirement R5).
- Notification of planned outages of telemetry equipment (TOP-001-2, Requirement R6).
- Not operating outside of identified Interconnection Reliability Operating Limits (IROLs) for a duration exceeding the associated T_v (TOP-001-2, Requirement R7).

- Notifying the Reliability Coordinator of System Operating Limits (SOLs) that support reliability internal to its Transmission Operator Area (TOP-001-2, Requirement R8).
- Not operating outside of the identified SOLs for a continuous duration that would cause a violation of its ratings (TOP-001-2, Requirement R9)
- Informing the Reliability Coordinator of actions to return the system within limits (TOP-001-2, Requirement R10)
- Mitigating the magnitude and duration of limit exceedances (TOP-001-2, Requirement R11)
- Requirements to have an Operational Planning Analysis (TOP-002-3, Requirement R1)
- Planning to preclude operating in excess of limits identified in the Operational Planning Analysis (TOP-002-3, Requirement R2)
- Notifying entities identified in plans of their roles in the plan (TOP-002-3, Requirement R3)
- Development of a data specification for all needed operating and planning data (TOP-003-2, Requirement R1 for the Transmission Operator and Requirement R2 for the Balancing Authority)
- Distribution of the data specification to affected entities (TOP-003-2, Requirement R3 for Transmission Operators and Requirement R4 for Balancing Authorities)
- The need to satisfy the obligations of the data specification (TOP-003-2, Requirement R5)

3. Proposed Reliability Standards must be applicable to users, owners, and operators of the bulk power system, and not others

Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

The proposed Reliability Standards are applicable to users, owners, and operators of the bulk power system, and not others. The proposed standards are specifically applicable to Transmission Operators, Balancing Authorities, Generator Owners, Generator Operators, Interchange Authorities, Load-Serving Entities, Transmission Owners, and Distribution Providers; each is clearly a user, owner, or operator of the bulk power system.

4. Proposed Reliability Standards must be clear and unambiguous as to what is required and who is required to comply

> Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply. Each requirement clearly states the applicable entity (ies) and what they are required to do.

5. Proposed Reliability Standards must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation

> Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

The proposed Reliability Standards include clear and understandable consequences. Each requirement is assigned a Violation Risk Factor ("VRF") and a Violation Severity Level ("VSL") which supports the determination of a base penalty amount for violations of the requirements as required by the NERC Sanction Guidelines.

6. Proposed Reliability Standards must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner

> Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

The proposed Reliability Standards identify clear and objective criteria to support enforcement in a consistent and non-preferential manner. Each requirement has an associated measure, and each requirement clearly identifies the expected performance that will serve as the basis for development of compliance enforcement objectives, typically provided through the Reliability Standard Audit Worksheets. The language used in the requirements clearly identifies what is expected of the applicable entity.

7. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost

> Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

The proposed Reliability Standards achieve their reliability goal effectively and efficiently. Expanding the requirements to meet the reliability objectives of the standards was carefully considered in the *Reliability Standards Development Process*, and the standards were structured to address the objective without unduly burdening the applicable entities.

8. Proposed Reliability Standards cannot be "lowest common denominator," *i.e.*, cannot reflect a compromise that does not adequately protect bulk power system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the

> ERO should not propose a “lowest common denominator” Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed Reliability Standards are more stringent than current requirements. For example, treatment of IROLs within T_v is a more stringent requirement than in the previous version of the Reliability Standards because T_v may actually be less than 30 minutes and therefore a tighter time frame than what is required in the currently-effective Reliability Standard. This reflects a significant increase in responsibilities and expectations for applicable entities and clearly does not represent a lowest common denominator.

9. Proposed Reliability Standards may consider costs to implement for smaller entities but not at consequence of less than excellence in operating system reliability

> Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a “lowest common denominator” Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

The proposed Reliability Standards do not differentiate among entities based on size or cost. These requirements apply to an entity with responsibility for operations.

10. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one area or approach

> Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or

> regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

The proposed Reliability Standards are designed to apply throughout North America. The standards as drafted propose no regional differences or variances.

11. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid

> Order No. 672 at P 332. As directed by section 215 of the FPA, the

> Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability

> Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

There is no basis for anticipating that the proposed Reliability Standards will adversely affect competition or restrict Available Transmission Capability beyond what is necessary for reliability.

12. The implementation time for the proposed Reliability Standards must be reasonable

> Order No. 672 at P 333. In considering whether a proposed Reliability

> Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

The proposed Reliability Standards identify the proposed effective dates for the standards. The ten and twelve month periods following regulatory approval are to allow for entities to update processes, develop data specifications, and train operators on the revised requirements.

13. The Reliability Standard development process must be open and fair

> Order No. 672 at P 334. Further, in considering whether a proposed
>
> Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved
>
> Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC *Reliability Standards Development Procedure,* which was incorporated into the Rules of Procedure as Appendix 3A. In the ERO Certification Order, FERC found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system. NERC considers the comments of all stakeholders and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard for submission to the Commission.

The proposed Reliability Standards set out in **Exhibit A** have been developed and approved by industry stakeholders using the process found in NERC's *Reliability Standards Development Procedure*, and were approved by the NERC Board of Trustees on May 9, 2012 for filing with FERC. Therefore, NERC has utilized its approved standard development process in good faith and in a manner that is open and fair.

14. Proposed Reliability Standards must balance with other vital public interests

> Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

These standards are focused on ensuring that the transmission system operates in a reliable fashion. No other environmental, social, or other goals are reflected or considered in these standards.

15. Proposed Reliability Standards must consider any other relevant factors

> Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

> Order No. 672 at P 337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. the Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed Reliability Standard.

An overview of the issues raised in consideration of the proposed standards, included in **Exhibit I**, is presented in a matrix and demonstrates how industry comments from previous work, as well as directives from Order No. 693, were addressed in this standard development project.

Exhibit C

Implementation Plan for Proposed Reliability Standards

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Implementation Plan

Project 2007-03 Real-time Operations

Prerequisite Approvals

Some changes made in this project are dependent on corresponding changes being approved in:

- Project 2006-06, Reliability Coordination:
  - IRO-001-3 - Reliability Coordination – Responsibilities and Authorities
  - IRO-005-4 - Reliability Coordination – Current Day Operations
- Project 2007-09, Generator Verification:
  - MOD-025-2 - Verification and Data Reporting of Generator Real and Reactive Power Capability

TOP-001-2: Transmission Operations, TOP-002-3: Operations Planning and TOP-003-1: Operational Reliability Data cannot be implemented until all three of the above standards have been implemented.

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

Two drafting teams (Project 2006-06 and Project 2007-03) have coordinated on a common definition of Reliability Directive and agreed that the Reliability Coordination Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference.

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

Compliance with Standard

There are three standards associated with this project for which industry approval will be requested: TOP-001-2: Transmission Operations, TOP-002-3: Operations Planning, and TOP-003-1: Operational Reliability Data.

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							

TOP-001-2: Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X	X	X
TOP-004-2: Real-Time Transmission Operations	Retired							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-1: Response to Transmission Limit Violations	Retired							
PRC-001-2	Retired Requirements R2, R5, and R6.							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

Effective Date of Revised Standards

All requirements except TOP-003-2, Requirements R1 and R2 will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements except TOP-003-2, Requirements R1 and R2 become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Requirements R1 and R2 of TOP-003-2 will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R2 of TOP-003-2 become effective the first day of the first calendar quarter ten months following Board of Trustees approval.

The twelve month period is to allow for entities to update processes and train operators on the revised requirements. The two month differential for TOP-003-2, Requirements R1 and R2 is to provide time for recipients of a data specification to respond to the request for data.

Retirement Date for Existing Standards

The existing Standards shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements will be retired at midnight of the day immediately prior to the first day of the first calendar quarter twelve months following Board of Trustees adoption.

Exhibit D

Consideration of Comments

Project 2007-03
Real-time Transmission Operations

Related Files

Status:
The NERC Board of Trustees approved Project 2007-03 at their May 9, 2012 meeting.

Purpose/Industry Need:
The industry needs clearer, unambiguous and enforceable standards in order to effectively operate the Bulk Electric System.

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Applicable Standards:

- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

Draft	Action	Dates	Results	Consideration of Comments
Draft 7 **Standards for Real-time Operations** TOP-001-2	Recirculation Ballots Info>> Vote>>	04/27/12 - 05/06/12 (closed)	Summary>> Ballot Results: TOP-001-2	

Clean | Redline to Last Posting TOP-002-3 Clean | Redline to Last Posting TOP-003-2 Clean | Redline to Last Posting Implementation Plan Clean PRC-001-2 Clean | Redline to Last Approved **Supporting Materials:** Issues Database Clean VRF and VSL Assignment Documentation Clean | Redline to last posting • PER-001-0.1 • TOP-001-1 • TOP-002-2a • TOP-003-1 • TOP-004-2 • TOP-005-2 • TOP-006-2 • TOP-007-0 • TOP-008-1 **Mapping Document** Clean | Redline to last posting			TOP-002-3 TOP-003-2	
Draft 7 **Standards for Real-time**		04/11/12 - 04/20/12 (closed)	Summary>> Full Records	

Operations TOP-001-2 Clean | Redline to last posting TOP-002-3 Clean | Redline to last posting TOP-003-2 Clean | Redline to last posting Implementation Plan Clean | Redline to last posting PRC-001-2 Clean | Redline to last approved **Supporting Materials:** Comment Form (Word) Updated 3/26/12 Issues Database Clean | Redline to last posting VRF and VSL Assignment Documentation Clean | Redline to last posting • PER-001-0.1 • TOP-001-1 • TOP-002-2a • TOP-003-1 • TOP-004-2 • TOP-005-2 • TOP-006-2 • TOP-007-0	Successive Ballots and Non-binding VRF/VSL Polls Updated Info>> Info>> Vote>>	Non-binding Polls Extended until 4/23/12	Successive Ballot Results: TOP-001-2 TOP-002-3 TOP-003-2 Non-binding Poll Results: TOP-001-2 TOP-003-2	
	Comment Period Info>> Submit Comments>>	03/22/12 - 04/20/12 (closed)	Comments Received>>	Consideration of Comments**(9)**

• TOP-008-1 **Mapping Document** Clean | Redline to last posting				
Draft 6 **Standards for Real-time Operations** TOP-001-2 Clean | Redline to last posting TOP-002-3 ean | Redline to last posting TOP-003-2 ean | Redline to last posting **Supporting Material** Implementation Plan ean | Redline to last posting **Issues Database** ean | Redline to last posting **VRF and VSL Assignment Documentation** ean | Redline to last posting • PER-001-0.1 • TOP-001-1 • TOP-002-2a • TOP-003-1 • TOP-004-2 • TOP-005-2 • TOP-006-2 • TOP-007-0 • TOP-008-1 Comment Form (Word) Mapping Document	Successive Ballots & Non-Binding Polls of VRFs and VSLs Extension Info on Non-binding Polls>> Updated Info>> Info>> Vote>>	Successive Ballots: **01/03/12 - 01/12/12 (closed)** Non-binding Polls: **01/09/12 - 01/18/12** **Extension of non-binding poll for TOP-001-2 and TOP-003-2 until 01/19/12 (closed)**	Summary>> **Successive Ballot Results:** TOP-001-2 TOP-002-3 TOP-003-2 Comments Received>> **Non-binding Results:** TOP-001-2 TOP-002-3 TOP-003-2	
	Formal Comment Period Submit Comments>>	12/14/11 - 01/12/12 (closed)	Comments Received>>	Consideration of Comments**(8)**

Draft 5 Standards for Real-time Operations TOP-001-2 Clean | Redline to last posting TOP-002-3 Clean | Redline to last posting TOP-003-2 Clean | Redline to last posting **Supporting Material** Implementation Plan Clean | Redline to last posting Issues Database Clean | Redline to last posting VRF and VSL Assignment Documentation Clean | Redline to last posting • PER-001-0.1 • TOP-001-1 • TOP-002-2a • TOP-003-1 • TOP-004-2 • TOP-005-2 • TOP-006-2 • TOP-007-0 • TOP-008-1 Comment Form (Word)	Initial Ballot & Non-Binding Poll of VRFs and VSLs Vote>>	5/31/11 - 6/9/11 (closed)	Summary>> Full Record>> Non-Binding Results>>	
	Join Ballot Pool>>	4/26/11 - 5/25/11 (closed)		
	Formal 45-day Comment Period Submit Comments>> Info>>	4/26/11 - 6/9/11 (closed)	Comments Received>>	Consideration of Comments**(7)**

Draft 4 Standards for Real-time Operations TOP-001-2 Clean | Redline to Last Posting TOP-002-3 Clean | Redline to Last Posting TOP-003-2 Clean | Redline to Last Posting **Supporting Materials:** Implementation Plan Issues Database VRF and VSL Assignment Documentation Comment Form (Word)	Comment Period Submit Comments>> Info>>	08/04/10 - 09/03/10 (closed)	Comments Received>>	Consideration of Comments**(6)**
Draft 3 Standards for Real-time Operations TOP-001-2 Clean | Redline to Last Posting TOP-002-3 Clean | Redline to Last Posting TOP-003-2 Clean | Redline to Last Posting **Supporting Materials:** Comment Form (Word)	Comment Period Info>> Submit Comments>>	08/25/09 - 09/24/09 (closed)	Comments Received>>	Consideration of Comments**(5)**

Standards for Real-time Operations TOP-001-2 Clean | Redline TOP-002-3 Clean | Redline TOP-003-1 Clean | Redline TOP-004-3 Clean | Redline TOP-008-1 Redline from Last Posting(last posting included the wrong version of TOP-008-0) **Supporting Materials:** Comment Form (Word) Implementation Plan Clean | Redline	Comment Period Info>> Submit Comments>>	04/07/09 - 05/07/09 (closed)	Comments Received>>	Consideration of Comments(4)
Standards for Real-time Operations Draft Standards TOP-001-004 Clean TOP-001-008, PER-001 Redline **Supporting Materials:** Comment Form (Word) Implementation Plan (Note: The Implementation Plan contains a mapping table with explanations as to why things have been	Comment Period Info>> Submit Comments>>	10/07/08 – 11/20/08 (closed)	Comments Received>>	Consideration of Comments(3)

changed.)				
Nominations for Real-time Operations Standard Drafting Team Info>> Submit Nomination>>		11/13/07 - 11/30/07 (closed)		
Draft 2 SAR for Real-time Operations Draft SAR Version 2 clean | redline to last posting	Comment Period Info>> Submit Comments>>	08/07/07 - 09/07/07 (closed)	Comments Received>>	Consideration of Comments(2)
SAR for Real-time Operations Draft SAR Version 1	Comment Period Info>> Submit Comments>>	05/15/07 - 06/13/07 (closed)	Comments Received>>	Consideration of Comments(1)

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Consideration of Comments on First Draft of the Real-time Operations SAR for Transmission Operations and Balancing of Load and Generation

The Real-time Operations SAR requesters thank all stakeholders who submitted comments on Draft 1 of the Real-time Operations SAR. This SAR was posted for a 30-day public comment period from May 15 through June 13, 2007. The requesters asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 23 sets of comments, including comments from 62 different people from 43 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the SAR drafting team is recommending that the SAR be re-posted to include specific issues that were pointed out by the commenters:

- Inclusion of IRO-004, -005 & -006 in the scope.
- Correction to the reference in TOP-001-1, R2.
- Correction to the reference in TOP-002-2, R3.
- Clarified the reason for recommending the deletion of TOP-002-2, R8.
- Corrected the reference in TOP-002-2, R10.
- Removed the recommendation for deleting TOP-002-2, R11.
- Rewording of the recommendation in TOP-002-2, R14 & R15.
- Clarified the deletion requested in TOP-004-1, R1.

Based on stakeholder comments, the SAR DT is proposing to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Real-time_Operations_Project_2007-03.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Thad Ness	AEP	✓									
2.	Anita Lee (G2)	AESO		✓								
3.	Jeffrey V. Hackman	Ameren										
4.	Jason Shaver	ATC LLC										
5.	David Rudulph (G1)	Basin Electric Power Coop.										✓
6.	Brent Kingsford (G2)	CAISO		✓								
7.	Anthony Alford	CenterPoint Energy										
8.	Alan Gale (G1)	City of Tallahassee					✓					
9.	Greg Tillitson (G4)	CMRC										✓
10.	Gregory D. Rowland	Duke Energy	✓		✓							
11.	Ed Davis	Entergy Services, Inc.										
12.	Will Franklin	Entergy Services, Inc.										
13.	Steve Myers (G2)	ERCOT		✓								
14.	Doug Hohlbaugh	FirstEnergy	✓		✓		✓	✓				
15.	John Reed	FirstEnergy	✓		✓		✓	✓				
16.	David Folk	FirstEnergy	✓		✓		✓	✓				
17.	Ed DeVarona	Florida Power & Light	✓									
18.	Eric Senkowicz	FRCC										✓
19.	Joe Knight (G1)	Great River Energy										✓
20.	Roger Champagne (I) (G3)	Hydro-Québec TransÉnergie (HQT)	✓									
21.	Ron Falsetti (I) (G2) (G3)	IESO		✓								
22.	Matt Goldbert (G2)	ISO-NE		✓								
23.	Kathleen Goodman (I) (G3)	ISO-NE		✓								
24.	Brian Thumm	ITC Transco	✓									
25.	Eric Ruskamp (G1)	Lincoln Electric System										✓
26.	Donald Nelson (G3)	MA DPUC									✓	

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
27.	Michelle Rheault	Manitoba Hydro	✓		✓		✓	✓				
28.	Robert Coish (G1)	Manitoba Hydro										✓
29.	Terry Bilke (G1)	Midwest ISO										✓
30.	Mike Brytowski (G1)	Midwest Reliability Organization										✓
31.	Carol Gerou (G1)	Minnesota Power										✓
32.	Bill Phillips (G2)	MISO		✓								
33.	Guy V. Zito (G3)	NPCC										✓
34.	Al Adamson(G3)	NY State Reliability Council										✓
35.	Jim Castle (I) (G2)	NYISO		✓								
36.	Greg Campoli (G3)	NYISO		✓								
37.	Ralph Rufrano (G3)	NYPA	✓									
38.	Todd Gosnell (G1)	OPPD										✓
39.	Alicia Daugherty (G2)	PJM		✓								
40.	Bob Johnson (G4)	PSC										✓
41.	Philip Riley	Public Service Commission of SC									✓	
42.	Mignon L.Clyburn	Public Service Commission of SC									✓	
43.	Elizabeth B. Fleming	Public Service Commission of SC									✓	
44.	G. O'Neal Hamilton	Public Service Commission of SC									✓	
45.	John E. Howard	Public Service Commission of SC									✓	
46.	Randy Mitchell	Public Service Commission of SC									✓	
47.	C. Robert Moseley	Public Service Commission of SC									✓	
48.	David A. Wright	Public Service Commission of SC									✓	
49.	Frank McElvain (G4)	RDRC										✓
50.	Tom Botello (G4)	SCE										✓
51.	Steve Wallace	Seminole Electric Coop.				✓						
52.	Roman Carter	Southern Company Transmission	✓									
53.	Jim Busbin	Southern Company Transmission	✓									
54.	J.T. Wood	Southern Company Transmission	✓									
55.	Marc Butts	Southern Company Transmission	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	Raymond Vice	Southern Company Transmission	✓									
57.	Jim Griffith	Southern Company Transmission	✓									✓
58.	Charles Yeung (G2)	SPP		✓								
59.	Nancy Bellows (G4)	WACM										✓
60.	Jim Haigh (G1)	WAPA										✓
61.	Neal Balu (G1)	WPSR										✓
62.	Pamela Oreschnick (G1)	Xcel Energy										✓

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – MRO Members
G2 – IRC Standards Review Committee (IRC SRC)
G3 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G4 – WECC Reliability Coordination Comments Work Group (RCCWG)

Index to Questions, Comments, and Responses

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

Summary Consideration: The SAR drafting team appreciates that the industry is near consensus on the removal of 'good utility practices' from NERC standards. We recognize that care must be taken to continue to require compliance with a necessary and sufficient set of standards for the continued reliable operation of the Bulk Electric System while moving some of the existing language from standards into reference documents. We also note that reference documents must be made readily available for continued usage. Our detailed responses are listed with each comment.

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
ATC LLC	☑		Standards define "good utility practices" therefore it's our opinion that these requirements should remain.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team appreciates your comment and agrees that any requirement that is strongly linked to assuring reliability, very specific, and consistently measurable should remain in the standards. General statements that are typically hard if not impossible to measure should be removed from the standards. 'Good utility practice' spans a wide range of acceptable practices, while standards set a specific bar that all must meet. Standards should not codify procedures that are simply one way of meeting a standard requirement.			
Manitoba Hydro	☑		If the "procedures and good utility practice" are enforceable, the above requirements should remain in the standards. If these requirements are removed from the standard, where will the reference documents be located? An attachment to the Standard or a separate manual not quickly and easily accessible to those who need it?
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team has not considered the ultimate location of any reference material. The SAR DT will pass this comment on to the NERC staff in order to come to a reasoned conclusion. One good location that could be considered would be a 'references' section on the NERC web site. The intent should be to have the reference documents readily available for consultation as well as for use in developing training.			
FirstEnergy	☑		FirstEnergy agrees in general that Good Utility Practices in and of themselves do not belong in the standards. However, for the two examples cited we believe these are important processes for ensuring a reliable electric system and therefore should remain within the reliability standards. Exclusion of requirments based on Good Utility Pratices will

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
			need to be evaluated and addressed on a case by case basis and commented on via the standard drafting process.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team agrees with the concept of addressing these issues on a case by case basis. The examples cited may ultimately be considered to be requirements; the team was attempting to amplify the concept of removing redundant and superfluous requirements to help deal with the unavoidable angst that was expected to occur due to the idea of removing some standards when this SAR was posted for comments. We will pass your comments along to the eventual Standards Drafting Team.			
City of Tallahassee	☑	☑	I am all for removing items that are "not standards" from the standards. However, references can be hard to keep track of. And they will "creep" into standard via the Readiness Assessment process. Each "requirement" up for deletion should be reviewed individually. Even the SAR drafting team disagrees on them. The example cited above (TOP-001-1, R7) is slated for revision in the Detailed Description portion of the SAR itself. The TOP-002-2, R2 should be removed.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team agrees with your comments. Each requirement will be reviewed individually to assure that it is necessary and not redundant. We had debated whether to revise or delete TOP-001-1, R7 and wrote it up to revise it for now. These comments will be passed on to the Standards Drafting Team.			
Duke Energy	☑	☑	Where the identification of procedures and good utility practice bring clarity to TOP requirements, they should be retained, although not as separate requirements.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team agrees with your comments. The structure of NERC standards are such that the usual background and explanatory material that once were contained in the NERC Operating Policies have no formal spot for archiving these types of issues. The Standards Drafting Team should work with NERC staff to assure that the clarity remains while not inadvertently retaining additional, unnecessary requirements.			
NYISO	☑	☑	Each case should be reviewed on an individual basis. It was not clear in the examples you provided. It is possible that some procedures may need to be reworded into standard language and for others it may be appropriate to move to a reference document.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team agrees with your comments. Industry comments indicate that each and every requirement that is necessary to			

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
assure continued reliable operation of the Bulk Electric System should be retained. The SAR DT will pass this comment on to the NERC staff in order to come to a reasoned conclusion on the topic of a reference document. One good location that could be considered would be a 'references' section on the NERC web site. The intent should be to have the reference documents readily available for consultation as well as for use in developing training. It is also clear that each individual change will need an explanation in order to gain industry consensus. The SAR drafting team found that our deliberations tended to link the various requirements across several standards, and that only by considering several at once did redundancies appear. It will behoove the Standards Drafting Team and NERC to fully explain the need for each change in order to help the balloting group gain confidence that the course being plotted will result in continued reliable operation of the Bulk Electric System.			
IESO			We concur that good utility practices and administrative procedures should not be included in standards. Nonetheless, we suggest the SDT to assess which of the existing requirements, including the procedural ones, are indeed actions needed to preserve reliability and hence keep them in the standards. While we agree that TOP-002-2, R2 may be removed, we do not agree that TOP-001-1 R7 should be removed since the notification and coordination of generation and transmission outages are necessary to ensure that reliability impact of the planned removal of the BES facility is assessed. It is not an administrative procedure or good utility practice; it is a reliability requirement.
Response: The SAR drafting team thanks you for your comments and has taken them under advisement. The reason that the SAR includes the elimination of the examples cited is to remove redundancy. In the specific case of TOP-001-1, R7, the requirement is basically "don't burden your neighbors" and "tell the RC what is going on". The additional language in R7 and its sub-requirements is unnecessary. TOP-003-0, R1.2 already requires data sharing to enable outage coordination to avoid burdening neighbors. TOP-001-1, R3 requires all BA/TOP/GOs to comply with RC reliability directives. Finally, IRO-004-1, R6 requires the RC to issue reliability directives to BA/TOP/GOs if the results of their studies indicate potential SOL or IROL violations. Therefore, this issue is already covered in other areas and is redundant in this location and should be removed. However, the Standards Drafting Team will make the final decision on the form that the standard will take when it goes to ballot.			
HQT			We agree that good utility practice and procedures should not be included in standards. However, care should be taken not to remove coordination requirements which are in fact necessary to reliability planning and operation.

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
ISO-NE			We agree that good utility practice and procedures should not be included in standards. However, care should be taken not to remove coordination requirements which are in fact necessary to reliability planning and operation.
NPCC CP9 RSWG			We agree that good utility practice and procedures should not be included in standards. However, care should be taken not to remove coordination requirements which are in fact necessary to reliability planning and operation.
Response: The team thanks you for your comments and is in agreement that reliable interconnected operation requires coordination which would continue to be enforced by specific standards.			
IRC SRC			Good utility practices and procedures should not be included in standards. They are vague statements and do not belong in the standards even as a reference. If good utility practice statements were acceptable there would only be a need for one requirement and that is that all entities shall institute good utility practice. True standards need to be developed and superfluous information should not remain in the standards.
Response: The SAR drafting team thanks you for your support on this issue. The sentiment expressed in your comment is exactly what we were thinking in asking this question. NERC standards must have a strong link to assuring reliability, be very specific, and consistently measurable.			
WECC RCCWG			The WECC RCCWG believes that some provisions of TOP-001-1 R1 are standard requirements, and that whether TOP-002-2 R2 is a standard requirement is less clear. The group agrees that in order to be a standard requirement there needs to be a link to an impact on the Bulk Electric System. The requirements need to be reworded to be measurable and substantiable.
Response: The SAR drafting team thanks you for your comments and is in agreement. Your comment identified yet another requirement which needs scrutiny if it is to remain in NERC standards.			
Entergy (Franklin)		☑	Move to reference documents or eliminate 'good practices' from standards, and also eliminate redundant requirements.
ERCOT		☑	Such information is of value and should not be lost, but does not belong in a Standard. A Standard must apply continent-wide and not be of the nature of dictating any particular practice or procedure.

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
MRO		☑	While we agree that the procedures and good utility practices do not necessarily need to be in the standard itself, the reference documents must be issued concurrent with the implementation of the revised standard. There is a great deal of information that is very useful for the utilities implementing the standards.
FRCC		☑	Subjective commentary that is not measurable or enforceable should be removed from the standards and placed in the Reliability Readiness Evaluation and Improvement Program Reference Manual or something similar.
Response: The SAR drafting team agrees with your comments. The decision of when or whether to issue reference documents will be passed to the Standards Drafting Team and NERC staff. We agree that the concepts included in this SAR which may be moved to reference material are of such importance that the reference material publishing schedule will need to be prompt in order to minimize concern over the potential loss thereof.			
AEP		☑	
Ameren		☑	
Entergy (Davis)		☑	
ITC Transco		☑	
PSC SC		☑	
SOCO Transmission		☑	
Response: The SAR drafting team thanks you for your support on this issue.			
CenterPoint			No comment.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on 'good utility practice'. Do you agree?**

Summary Consideration: Based on stakeholder comments, the SAR DT is proposing to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs.

The SAR DT believes that the sole purpose of NERC standards is to ensure BES reliability. The majority of the team believes that NERC standards are not intended to cover local events which have no impact on neighboring system reliability. The requirements currently embedded in NERC standards exist due to many reasons. During the V0 drafting effort massive duplication of requirements was noticed by the drafting team but left within the standards due to the mandate to "not change anything, just re-format it for standards".

SOLs, by NERC's own definition, are not cascading events. This does not mean that they are not important (and RCs are still required to monitor them) but there is no reliability reason to require some entity to not violate an SOL. Interconnected Transmission Systems must continue to operate so as not to burden their neighbors or risk BES reliability. These are fundamental requirements for continued reliable operation of the BES. If you follow all of the other standards for planning and operational planning, such as FAC-011 and the IRO standards, you should never find yourself within one Contingency of violating an IROL.

Question #2			
Commenter	**Yes**	**No**	**Comment**
AEP		☑	We disagree with this statement. Just what does the SAR DT consider to be a true BES reliability issue? The team's opinion seems contradictory to NERC's efforts to have the Regions agree that all non-radial transmission facilities 100 kV and above are Bulk Electric System facilities. On one end of the spectrum there is a NERC effort to expand the definition and size of BES. Then you efforts like this SAR to reduce the size and scope. While the most severe and significant BES reliability issue may be IROL violations (IROL violations can lead to instability, uncontrolled separation, or cascading outages), that surely is not the only reliability issue. Multiple SOL events can lead to a situation where you have a new, non-studied IROL. Should we not operate the system such to prevent us from entering or approaching IROL limits? If the only limits that have applicable Reliability Standards is IROLs, then are we not setting up the system to approach the "edge of the cliff" before we take appropriate defensive action? While we agree not all

Question #2			
Commenter	**Yes**	**No**	**Comment**
			SOLs have a significant impact on the overall reliability of the BES, we do not agree that means all requirements related to SOLs should be removed from the NERC Standards. That would be a move towards less reliability in the future, not a step towards improving reliability. And just what is meant by local utility operations not being a true BES reliability issue. If the system is not operated to respect SOLs, then that could jeopardize a firm power purchase from a distance resource via firm transmission service that a "local utility" is relying upon. Loss of that firm power purchase, could lead to having to shed customer load? Why is that not a BES reliability issue? Isn't that one of the reasons the BES exists is to support such commerce? Violating SOLs could also result in the tripping of generation outlets, resulting in loss of generation. That too is not a BES reliability issue? Before we could support removing requirements related to SOLs, the SAR DT team would need to provide a definition of what exactly is considered a BES reliability issue. Most of the TLRs that are implemented today are for relieving SOLs not IROLs. Therefore, removing requirements related to SOLs would be in direct conflict with current practices and does not improve the reliability practices from what we have today. At a minimum, RCs and TOPs need to monitor and know the EHV system SOLs and ensure operation within those SOLs and to monitor and operate to other SOLs as specified in the agreements between the RC and TOPs and BAs (see ORG-021-1 R3). While it is not practical or necessary to ticket every car speeding on the freeway, on the contrary it is also not practical or necessary to remove the speedometer from the cars. We feel that the requirements for the SOL are like the speedometers; therefore, removing requirements related to SOLs is inappropriate and could lead to less reliable operations.
Response: The SAR drafting team is utilizing the definition of SOL developed in FAC-011-1 which states that: R1.2 …SOLs shall not exceed associated Facility Ratings. R2.1 …In the pre-contingency state, the BES shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage, and stability limits. R2.2 Following the single Contingencies identified in Requirements 2.2.1 through 2.2.3, the system shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be operating within their Facility Ratings; and within their thermal, voltage, and stability limits; and Cascading Outages or uncontrolled separation shall not occur. FAC-011-1 also requires that the RC; R1.3**.** Include a description of how to identify the subset of SOLs that qualify as IROLs.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
The SAR drafting team concludes from this that SOLs, "… while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on 'good utility practice'." Nor do we find anything in your comments that leads us to believe otherwise. According to FAC-011-1, unless and until SOLs qualify as IROLs they are not a threat to BES reliability and do not require RCs to do more than monitor their status.			
ATC LLC		☑	ATC does not agree with SAR DT that SOLs are only important to local operations and that they should be removed from these standards. If SOLs are removed from NERC standards then any real-time identifications of an SOL that becomes an IROL will be difficult if not impossible to determine.
Response: As noted above, the SAR drafting team is utilizing the definition of SOL developed in FAC-011-1 which requires that the RC ; R1.3**.** Include a description of how to identify the subset of SOLs that qualify as IROLs. The SAR drafting team concludes from this that SOLs can either be effectively identified prior to the time they become IROLs, or they will be flagged for RC attention since they fail the requirement of R1.3 and demand special processing from the TOP and RC. According to FAC-011-1, unless and until SOLs qualify as IROLs or are identified as impossible to classify, they are not a threat to BES			
Duke Energy		☑	Where SOLs impact the Bulk Electric System, they are a reliability issue and should not be moved into guides or other reference documents.
Response: As noted above, the SAR drafting team is utilizing the definition of SOL developed in FAC-011-1 which requires that the RC: R1.3**.** Include a description of how to identify the subset of SOLs that qualify as IROLs. The SAR drafting team concludes from this that SOLs which will impact the reliability of the BES will be identified as IROLs and treated appropriately as per the requirements of IRO-005-2, IRO-006-3 and others.			
IESO		☑	We strongly disagree with this notion. Respecting SOLs and mitigating their violations are fundamental to the reliable operation of the transmission operator's area which may ultimately affect the interconnected system. And since IROLs are a subset of SOLs, and that some SOLs may become IROLs as system condition changes, it is imperative that all SOLs be monitored and observed at all time.
City of Tallahassee		☑	- Without a standard requiring action on SOL's, many entities will live with them in the hope that nothing else will happen. - If you make the RC aware of small problems (SOL), they can be corrected before they are big problems (IROL).

Question #2			
Commenter	**Yes**	**No**	**Comment**
			- The determination of whether an SOL is an IROL is made by the RC. If there is no notification, how can he make that determination? - Some coordination of SOL remediation may need to occur between entities. The corrective action I want to take may put my neighbor in extremise. The coordination is best done while keeping the RC informed.
Response: As noted above, the SAR drafting team agrees with you, but notes that this requirement is already covered by IRO-005-2 which states that : R1**.** Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following: R1.2**.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. R1.3**.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. Your comment appears to be covered by IRO-005-2. The SAR DT reviewed the proposed deletion of R10 and R11 from TOP-002-2 and made the following modifications to this posting: ▪ R10: delete due to duplication with TOP-004-0, R1; ▪ R11: shall remain.			
FRCC		☑	SOLs are a critical part operational situational awareness and of a "defense-in-depth" approach to operating reliably. It is critical for the Transmission Operator and Reliability Coordinator to be aware of areas that are stressed within his/her TOP and RC area (local and wide area view). Advance knowledge of what may initially be local or even minor issues to the BES, will allow the development of the most effective and appropriate solutions for resolving the SOLs and ensuring that they DO NOT evolve into IROLs.
NPCC CP9 RSWG HQT ISO-NE		☑	We strongly disagree with this idea. Respecting SOLs is a fundamental operational requirement. Transmission Operators must be required to closely montior their area; failing to do so may ultimately lead to cascading failures, as was witnessed on August 14, 2003. An SOLs, left unchecked, will become an IROL, which is why it is imperative that all SOLs be monitored and respected at the TOP level.
ITC Transco		☑	While SOLs may be local in nature, the mitigation of SOL violations has the potential to impact several entities of the functional model - oftentimes from different companies. Without a standard, it will be difficult to properly justify actions taken to mitigate SOL violations.

Question #2			
Commenter	**Yes**	**No**	**Comment**
NYISO		☑	SOLs should be retained as part of the NERC Standards. The NYISO does not believe that SOLs are only important to local operations. SOLs also occur on BPS facilities and can cause reliability issues outside of the local utility operations, without being an IROL.
Response: The SAR DT reviewed the proposed deletion of R10 and R11 from TOP-002-2 and made the following modifications to this posting: ▪ R10: delete due to duplication with TOP-004-0, R1; ▪ R11: shall remain. TOP-002-2, R11 requires "The Transmission Operator shall …. determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator." This requirement means that the TOP must be aware of SOLs. TOP-006-0, R2 requires "Each Reliability Coordinator, **Transmission Operator**, and Balancing Authority **shall monitor** applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources." This requirement addresses the comment that 'Transmission Operators must be required to closely monitor their area'.			
SOCO Transmission	☑	☑	There are many Standard requirements outside the scope of this SAR which require the RC to "monitor" potential SOLs. As an example, IRO-003, R1 says each Reliability Coordinator shall monitor all Bulk Electric System facilities to ensure the RC is able to determine any potential System Operating Limit. If this SAR removes the standards in scope that mention SOLs but leaves IRO-003, R1, to be enforced, then ambiguity will result. IRO-003, R2 says each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL. Again, it appears in other standards (outside the scope of this SAR) that the RC is responsible (enforceable requirement) for being aware of preliminary events that could lead to an SOL. Additionally, IRO-002, R6 also contains such references to SOLs as well as other IRO Standards. Therefore, it appears the scope of the SAR should be broadened to include other standard requirements not contained in this SAR.
ERCOT	☑		There may be some confusion across the industry about "what are SOLs". I think there is good agreement that IROLs are applicable at the NERC Standard level, but there is

Question #2			
Commenter	**Yes**	**No**	**Comment**
			some identifiable reluctance within the industry to say that there is no place at all for SOLs in the NERC Standards. At the very least, there needs to be a good definition of SOL (which I believe there is), but some are concerned with the idea that IROLs are a "subset" of SOLs. Some believe that once a differentiation is made, the two should be considered separately and have separate requirements. I personally believe that IROLs are a subset of SOLs. I further believe that routine planning, operations planning, and real-time operations should be addressing all SOLs. Only during real-time operations or, more accurately, fresh post-analysis, can it be fully determined that an SOL may have sufficient consequences associated with it to qualify it as an IROL. If an IROL can be identified in advance, since by definition it relates to a single contingency, I believe a case could be made that planning and operations planning requirements have not been satisfied. In the great majority of cases, a system may be driven into an IROL through a series of unplanned events such that the system indeed may be subject to undesirable results from a "next" single contingency. However, prudent operations should dictate that no system plan to be in such a state.
MRO	☑		A System Operating Limit (SOL) does not necessarily need to be included in the standard itself, but the literature on Good Utility Practice must be issued concurrent with the implementation of the revised standard. There is a great deal of information that is very useful for the utilities implementing the standards. To aid understanding of a System Operating Limit (SOL), it would be very helpful to add some examples of a SOL in the Glossary of Terms.
Response: The SAR drafting team thanks the commenters for their input.			
FirstEnergy	☑		The reliability standards governing real-time operations should be focused on the subset of SOLs that qualify as IROLs.(reference FAC-010-1 R1.3). Blanket removal of all SOL references should be avoided and will need to be done on a case by case basis.
Response: The SAR drafting team agrees that care must be taken to consider each standard on a case to case basis, but with overall considerations as to how the standards work together to form a coherent whole.			
WECC RCCWG			While it is true that some SOLs do not have Bulk Electric System impact, such as a wave trap or customer transformer overload (local issues), others may lead to an impact on the Bulk Electic System. The group feels that if it can be shown through studies that a SOL does not have an impact on the Bulk Electic System, that particular SOL could be exempted from standards requirements. The group also questions whether a SOL without Bulk Electric System impact, but with potential local impact that would require a NERC disturbance report should be a standard requirement.
Response: Every SOL that qualifies as an IROL is covered by applicable standards such as IRO-004, -005 & -006.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		
Entergy (Davis)	☑		
CenterPoint			No comment.
Entergy (Franklin)			No comment.
IRC SRC			No comment.
PSC SC			No comment.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the Standards Drafting Team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the Standards Drafting Team?**

Summary Consideration: Industry consensus is to pass along all accumulated comments to the Standards Drafting Team for their consideration. (Note that the SAR DT revised the SAR to include comments recommending specific modifications to specific requirements that were provided by stakeholders during this comment period.)

Question #3			
Commenter	**Yes**	**No**	**Comment**
ATC LLC		☑	Comments submitted during the comment period should be given a greater weight in the creation of new standards. Comments submitted to other groups and different efforts are specific to those initiatives and the inclusion in this effort should be limited.
Response: The SAR DT agrees and the weight of consensus of the industry will govern the final response.			
CenterPoint		☑	CenterPoint Energy disagrees with the suggestion to remove the real and reactive capability verification testing from TOP-002-2, R13. The capability of a generator must be periodically tested to ensure that the machine will perform to its limits. Additional language should be added such that these tests are conducted on a periodic basis and not just at the requests of a BA or TOP. CenterPoint Energy believes that the requirements of TOP-002-2, R14 and R15 do belong in the Transmission Operations Standards as those variables will have a direct impact on daily operations. Any additional details or clarification can be added to other standards if necessary.
Response: The reason that this was included in the SAR is that it was considered duplicative with MOD-024 & MOD-025 by the CESDT. This point needs to be considered by the Standards Drafting Team.			
Duke Energy	☑	☑	Comments submitted should certainly be considered by the standard drafting team, but the standard drafting team should not be bound to incorporate all comments into the revised standards.
Response: The SAR DT agrees and the weight of consensus of the industry will govern the final response.			
SOCO Transmission	☑	☑	This SAR does not provide the referenced assessments the SAR drafting team has made on comments contained in Appendix B. Therefore, we can not agree or disagree with the team's assessment.

Question #3			
Commenter	**Yes**	**No**	**Comment**
Response: Thank you for your comment. Basically, the SAR DT made the decision to simply pass on the aggregated comments to the Standards Drafting Team.			
WECC RCCWG			The references, such as FERC Order 693, are so detailed that the WECC RCCWG does not believe the group can comment on the standard drafting team assessment of those comments.
Response: Thank you for your comment. Basically, the SAR DT made the decision to simply pass on the aggregated comments to the Standards Drafting Team.			
AEP	☑		Yes, we agree that the Standard Drafting Team should review and consider the merits of those comments and incorporate those comments that make sense and our complimentary to maintaining and improving reliable operations into the revised Standards.
ERCOT	☑		Each submitted comment containing technical content deserves to be given equal review by the Standard Drafting Team (SDT) once a SAR has been approved and a SDT has been selected.
IESO	☑		This seems to be a reasonable approach. However, the SDT should take these into consideration only when reviewing and revising the standards, and use its judgment on their individual merit rather than taking them as given mandates or directives.
FRCC	☑		Not sure what the question is but, Yes capturing previous analysis regarding standard content and including in this SAR and subsequent standard revisions is appropriate and effective use of previous NERC groups efforts.
NPCC CP9 RSWG HQT IRC SRC ISO-NE	☑		This may be a reasonable approach. However, the SAR DT may want to consider if they then need to pass all comments dealing specifically with the standards on to the Standards Drafting team from this process.
NYISO	☑		This may be a reasonable approach. The NYISO would recommend that all subsequent comments be provided to the Standards Drafting Team for consiration in revising the standards.
Response: Thank you for your comment.			
Ameren	☑		
Entergy (Davis)	☑		
Entergy (Franklin)	☑		
ITC Transco	☑		
Manitoba Hydro	☑		

Question #3			
Commenter	**Yes**	**No**	**Comment**
MRO	☑		
PSC SC	☑		
City of Tallahassee	☑		
FirstEnergy	☑		
Response: Thank you for your support.			

4. **Are there any standards included in the SAR that shouldn't be included?**

Summary Consideration: The SAR DT believes that there was not a consensus to delete any standards and the best way to address these comments is to pass them on to the eventual SDT and allow them and the industry (through balloting) to make the final decision.

Question #4		
Commenter	**The following standards were included in the SAR and should be removed:**	**Comment**
Duke Energy		COM-001-1, COM-002-2 and PER-001-0. See response to question 7.
Response: The weight of the industry consensus is that real-time is not restricted to just TOP standards and should include COM and PER.		
IESO		(i) We do not understand the basis to include COM-001-1, COM-002-1 and EOP-001-0 in this SAR. While there are requirements in these standards that reference TOPs, there are other standards that also reference TOPs but they are not included in this set. (ii) Some of the standards included in this SAR for revision appear to create a coordination need or potential conflicts with other SARs and draft standards: (a) The Operating Personnel Communications Protocol (OPCP) SAR is proposing to modify COM-001-1, COM-002-1, TOP-001-1, TOP-002-2, TOP-007-0 and TOP-008-1. How does this SAR Drafting Team propose to coordinate with the OPCP SAR drafting team to avoid either duplicated work effort or making changes to these standards while the draft set proposed by the other SDT are being commented or balloted? It seems like this would be difficult to accomplish and that one SAR should be delayed. (b) The Operate within Interconnected Operating Limits SDT is in the process of modifying the TOP-003, TOP-005, and TOP-006 standards as a result of changes to IRO-007-1 to IRO-011-1 standards. The coordination issues as indicated above would also need to be considered. We suggest that drafting of the standards included in

Question #4		
Commenter	**The following standards were included in the SAR and should be removed:**	**Comment**
		this SAR be put on hold until after the IRO standards are balloted and approved. (c) The Reliability-based Control SAR, which will develop the BAL-007 to BAL-011, standards is posted for comments. The coordination issues as indicated above would also need to be considered. We suggest that drafting of the standards included in this SAR be put on hold until after the BAL standards are balloted and approved. (d) Finally, the System Personnel Training drafting team is proposing to eliminate PER-001 through PER-004. This SAR would have to be updated to reflect those changes. Again this SAR should be put on hold until the PER standards are balloted.
Response: 1. The basis for inclusion of certain standards in this SAR is the comments received from various groups that clearly indicated the need to coordinate issues in different standards such as COM with real-time operations. This is being done to promote consistency and eliminate redundancy in the standards. **2.** All this SAR is trying to do is to point out possible redundancies in the standards. Your comments will be passed on to the eventual Standards Drafting Team. It will be up to them and the NERC staff to resolve any potential conflicts.		
MRO		There are several TOP standards currently under revision in other SAR's. There must be clear coordination between the Drafting Teams of the various SAR's as they are revising the Reliability Standards.
HQT		Some of the standards included in this SAR for revision appear to create a conflict with other ongoing SAR and Standard drafting activities. We are becoming more and more concerned about the parallel changes taking place.
IRC SRC		We do agree that this SAR appears to cover the right set of standards. However, it potentially conflicts with other SARs and draft standards. The Operating Personnel Communications Protocol (OPCP) SAR is proposing to modify COM-1-1, COM-002-2, TOP-001-1, TOP-002-2, TOP-007-0, TOP-008-0 standards. All of these standards are proposed to be modified in this SAR. How does this SAR Drafting

Question #4		
Commenter	**The following standards were included in the SAR and should be removed:**	**Comment**
		Team propose to coordinate with the OPCP SAR drafting team. It seems like this would be difficult to accomplish and that one SAR should be delayed. The Operate within Interconnected Operating Limits Standard Drafting team is in the process of modifying the TOP-003, TOP-005, and TOP-006 standards. Assuming these standards are eventually approved, this SAR will have to be modified to reflect the new versions of the standards. Again, this SAR should be delayed until the Operate within Interconnected Operating Limits Standards have completed the ballot process. Finally, System Personnel Training drafting team is proposing to eliminate PER-001 through PER-004. This SAR would have to be updated to reflect those changes. Again this SAR should be delayed until these standards are balloted.
ISO-NE		Some of the standards included in this SAR for revision appear to create a conflict with other ongoing SAR and Standard drafting activities. We are becoming more and more concerned about the parallel changes taking place.
NYISO		We do agree that this SAR appears to cover the right set of standards. However, it potentially conflicts with other SARs and draft standards. The Operating Personnel Communications Protocol (OPCP) SAR is proposing to modify COM-1-1, COM-002-2, TOP-001-1, TOP-002-2, TOP-007-0, TOP-008-0 standards. All of these standards are proposed to be modified in this SAR. How does this SAR Drafting Team propose to coordinate with the OPCP SAR drafting team. It seems like this would be difficult to accomplish and that one SAR should be delayed. The Operate within Interconnected Operating Limits Standard Drafting team is in the process of modifying the TOP-003, TOP-005,

<table>
<tr><th colspan="3">Question #4</th></tr>
<tr><th>Commenter</th><th>The following standards were included in the SAR and should be removed:</th><th>Comment</th></tr>
<tr><td></td><td></td><td>and TOP-006 standards. Assuming these standards are eventually approved, this SAR will have to be modified to reflect the new versions of the standards. Again, this SAR should be delayed until the Operate within Interconnected Operating Limits Standards have completed the ballot process.

Finally, System Personnel Training drafting team is proposing to eliminate PER-001 through PER-004. This SAR would have to be updated to reflect those changes. Again this SAR should be delayed until these standards are balloted.</td></tr>
<tr><td>NPCC CP9 RSWG</td><td></td><td>Some of the standards included in this SAR for revision appear to create a conflict with other ongoing SAR and Standard drafting activities. We are becoming more and more concerned about the parallel changes taking place.</td></tr>
<tr><td colspan="3">Response: All this SAR is trying to do is to point out possible redundancies in the standards. Your comments will be passed on to the eventual Standards Drafting Team. It will be up to them and the NERC staff to resolve any potential conflicts.</td></tr>
<tr><td>Entergy (Davis)</td><td>No.</td><td></td></tr>
<tr><td>WECC RCCWG</td><td></td><td>None are currently identified, but some may become apparent later.</td></tr>
<tr><td>SOCO Transmission</td><td></td><td>No comment.</td></tr>
<tr><td>AEP</td><td></td><td>No comment.</td></tr>
<tr><td>Ameren</td><td></td><td>No comment.</td></tr>
<tr><td>ATC LLC</td><td></td><td>No comment.</td></tr>
<tr><td>CenterPoint</td><td></td><td>No comment.</td></tr>
<tr><td>Entergy (Franklin)</td><td></td><td>No comment.</td></tr>
<tr><td>ERCOT</td><td></td><td>No comment.</td></tr>
<tr><td>Manitoba Hydro</td><td></td><td>No comment.</td></tr>
<tr><td>PSC SC</td><td></td><td>No comment.</td></tr>
<tr><td>City of Tallahassee</td><td></td><td>No comment.</td></tr>
<tr><td>FirstEnergy</td><td></td><td>No comment.</td></tr>
<tr><td>FRCC</td><td></td><td>No comment.</td></tr>
<tr><td>ITC Transco</td><td></td><td>No comment.</td></tr>
</table>

5. Are there standards that should be added to the SAR?

Summary Consideration: The SAR will be re-posted to consider the inclusion of IRO-004, -005 & -006 in the scope.

Question #5		
Commenter	**The following standards should be added to the SAR:**	**Comment**
SOCO Transmission	IRO-002, IRO-003, IRO-005, IRO-006. However, there could be others.	
Response: The SAR DT agrees that IRO-006 should be included in the scope of this SAR for the sole topic of eliminating redundancies relating to the applicability of TOP's and BA's in the respective documents. We are uncertain about what the comments on IRO-002 & -003 mean. In reviewing this issue, it appears that IRO-004 & -005 have the same problems as IRO-006 and therefore should be included in the scope of this SAR. This will require a re-posting of the SAR for consideration by the industry.		
Entergy (Davis)	No.	
City of Tallahassee	None.	
Duke Energy	None.	
IESO	No.	
PSC SC	None.	
HQT	No.	
IRC SRC	No.	
ISO-NE	No.	
NYISO	No.	
NPCC CP9 RSWG	No.	
WECC RCCWG		None are currently identified, but some may become apparent later.

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

Summary Consideration: The consensus is that there is a reliability-related need for this SAR.

Question #6			
Commenter	**Yes**	**No**	**Comment**
ATC LLC	☑	☑	ATC agrees that there is a reliability-related need to review and revise this set of standards, but we do not agree with the overly prescriptive changes appearing in the SAR.
Response: The SAR is a scoping document and the changes represent topics that are open to debate. The SAR DT intended to be prescriptive only in defining the scope of the work area. The SAR DT did not intend to be prescriptive in the requirements being proposed. A SAR DT does not define solutions, and this DT did not intend to define solutions. How prescriptive the standard will be is decided by the comments to the Standard DT.			
ERCOT	☑	☑	I believe that revising the set of standards for clarity and for reducing redundancy will benefit reliability by reducing confusion. There is also a common sense reason to revise them to avoid "multiple jeopardy" by exposure to the same requirement in multiple standards.
Response: Thank you, the concept that reliability requires clear unambiguous standards has support from other commenters as well as from the SAR DT.			
WECC RCCWG			The WECC RCCWG believes that some of the standard requirements need to be clarified.
Ameren	☑		It is important that the standards address those things, and only those things, that affect the reliability of the BES so that time and attention are not diverted from the most worthwhile initiatives.
Duke Energy	☑		The reliability-related need is to provide clarity and remove redundancy.
Manitoba Hydro	☑		The standards must be revised to clearly define the responsible entity for each requirement. There can't be any room for a requirement to fall through the cracks because the assignment of responsibility is not clear. Redundancy between Standards does not mitigate the risk of inadequate assignment of responsibility, but rather it may increase the likelihood that responsible entities assume that the requirements are met by others.
MRO	☑		The current versions of the standards are very voluminous and confusing. These revisions should remove the ambiguity and lead to a small set of quality reliability related requirements to be complied with.
AEP	☑		
City of Tallahassee	☑		

Question #6			
Commenter	**Yes**	**No**	**Comment**
Entergy (Davis)	☑		
Entergy (Franklin)	☑		
IESO	☑		
PSC SC	☑		
FirstEnergy	☑		
FRCC	☑		
HQT	☑		
IRC SRC	☑		
ISO-NE	☑		
ITC Transco	☑		
NYISO	☑		
NPCC CP9 RSWG	☑		
SOCO Transmission	☑		
CenterPoint			No comment.

7. Do you agree with the scope of this SAR?

Summary Consideration: The consensus is that the industry agrees with the stated purpose of the SAR. However, as indicated in the response for question #5, there will be a re-posting of the SAR to consider the inclusion of certain IRO standards.

Question #7			
Commenter	**Yes**	**No**	**Comment**
ATC LLC		☑	The scope of this SAR is overly prescriptive in that is has already determined a solution to the perceived deficiency. A scope needs to be detailed enough to provide a solid base for discussion and review, but not so detailed that the solution has been identified. The solution will be developed by the SDT along with industry feedback. ATC believes that this SAR is overly prescriptive and should be re-written.
Response: The SAR is a scoping document and the changes represent topics that are open to consideration. The SAR DT intended to be prescriptive only in defining the scope of the work area. A SAR DT does not define solutions, and this DT did not intend to define solutions. How prescriptive the standard will be is decided by the comments to the Standard DT.			
Duke Energy		☑	This SAR should focus only on TOP standards.
Response: The intent of the SAR was to cover unresolved real time operations issues that had been raised by FERC and other commenters. The general industry favors the wider scope.			
IESO		☑	Please see our comments under Q2 and Q4 regarding the notion of the SAR DT, and the potential conflicts with other efforts currently underway or to start soon.
HQT		☑	Please see response to Q#4.
ISO-NE		☑	Please see response to Q#4.
NPCC CP9 RSWG		☑	Please see response to Q#4.
Response: The concern about coordination with other Standard Drafting Teams is addressed by the Standards Committee and the NERC Standards Process Manager. There is also a difference between standards and requirements. There are standards that appropriately fall under more than one NERC Project; however, the requirements within that given standard should be unique to a given DT. If there are any duplicative requirements, then that is best addressed in the Standards process. To limit the scope of this SAR because another SAR may also address the same standard may in the end preclude a needed change in a specific requirement.			
SOCO Transmission		☑	The SAR needs to be broadened in scope to cover all standard requirements that contain references of the RC being responsible for SOLs and not just a subset of standards.
Response: The intent of the SAR was to cover unresolved real time operations issues that had been raised by FERC and other commenters. There is a newly constituted SAR DT to address RC issues and standards that should address your concerns. If there are additional RC standards that need to be addressed, then a new SAR can be submitted.			

Question #7			
Commenter	**Yes**	**No**	**Comment**
IRC SRC	☑	☑	This SAR should be written to apply only to TOPs. This is an opportunity to create a good quality set of standards and eliminate the existing ambiguous requirements. You should start with a clean slate.
Response: The intent of the SAR was to cover unresolved Real Time Operations issues that had been raised by FERC and other commenters**.**			
ITC Transco	☑	☑	Except for not addressing the SOL issue described above.
Response: This was addressed in the responses to question #2.			
AEP	☑		We agree with the purpose stated for this SAR. We do not agree with all of the specific changes suggested in the SAR. However, the SAR is written that the Standard Drafting Team is to consider the changes, which we do support. We believe that through a thorough debate and analysis by the Standard Drafting Team, that they too will conclude that not all the recommendations should be implemented.
Response: Thank you for your support.			
MRO	☑		The current versions of the standards are very voluminous and confusing. These revisions should remove the ambiguity and lead to a small set of quality reliability related requirements to be complied with.
Response: Thank you for your support.			
Ameren	☑		
City of Tallahassee	☑		
Entergy (Davis)	☑		
Entergy (Franklin)	☑		
ERCOT	☑		
Manitoba Hydro	☑		
PSC SC	☑		
FirstEnergy	☑		
FRCC	☑		
NYISO	☑		

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR, please list them here.**

Summary Consideration: No specific comments upon the content of the SAR were submitted relative to this question.

Question #8			
Commenter	**Regional Variances**	**Business Practices**	**Comment**
MRO			We are not aware of any at this time, since we do not know the detailed changes and wording that will be in the Reliability Standards. It is imperative to include red-line versions of the revised standards to allow determination of what needs to be included in the reference documents.
Response: The SAR DT thanks MRO for its comment. The comment suggests a process that relates to the activities of the yet-to-be-established Standard Drafting Team. We agree that it is important to be able to see what specific changes are being recommended in the content of the specific standard(s) being revised, as well as any related standard(s).			
City of Tallahassee			None.
Duke Energy			None.
AEP			No comment.
Ameren			No comment.
ATC LLC			No comment.
CenterPoint			No comment.
Entergy (Davis)			No comment.
Entergy (Franklin)			No comment.
ERCOT			No comment.
IESO			No comment.
Manitoba Hydro			No comment.
PSC SC			No comment.
FirstEnergy			No comment.
FRCC			No comment.
HQT			No comment.
IRC SRC			No comment.
ISO-NE			No comment.
ITC Transco			No comment.
NYISO			No comment.
NPCC CP9 RSWG			No comment.
SOCO Transmission			No comment.
WECC RCCWG			No comment.

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Summary Consideration: Accommodating changes to the SAR will be made as noted below.

Question #9	
Commenter	**Comment**
AEP	AEP encourages additional aids (i.e. whitepapers and/or teleconferences) during the drafting process to better understand the drive for removing SOLs from some of the standards.
Response: The SAR drafting team agrees that more in depth discussion of the topic can serve only to improve understanding and improvement of standard requirements and we will pass this comment on to the SDT.	
ATC LLC	Comment in the SAR: "R14 and R15 apply to the Generator Operator and as such do not belong in the TOP standards. The drafting team should look to find another place for these requirements if possible." ATC disagree with this statement. The "Purpose" statement sets the need for the standard. All entities that are needed to support the "Purpose" should be identified in the Applicability section. The label of TOP should not be the justification to exclude any entity that is not a Transmission Operator.
Response: You make a very good point. We may have overstated the problem. The SAR will be changed to read: "R14 and R15 apply to the Generator Operator and as such may be better addressed in other standards. The Standards Drafting Team should look to find another place for these requirements if possible."	
Entergy (Franklin)	We agree that the proposed changes need to be evaluated. However, it is important that the revised standards are balloted separately so that the entire set is not rejected because of an issue with one of the standards nor approved as a set with flaws or concerns in one or more of the standards.
Response: The SAR drafting team will forward your comment to the Standard Drafting Team (SDT) when it is established. One of the important decisions the SDT must make is whether to vote all changes as one package or whether some of the changes may stand alone and may be balloted individually.	
Duke Energy	If the ultimate goal is to eliminate PER-001-0 as stated on page SAR-4, it should be noted that responsibility and authority are to be provided to "operating personnel" in either a TO or a BA. However, in standard TOP-001 Requirement 1, it deals specifically with Transmission Operators, and Balancing Authority personnel are not covered under this standard. Consideration should be given to either add BAs to TOP-001 R1 or they should be given "responsibility and authority" in some other standard if PER-001 is eliminated. Also, NERC should create a companion database for the standards that links each requirement, its compliance elements and applicable entities. Such a cross-reference would facilitate standards actions dealing with groups of standards.

Question #9	
Commenter	**Comment**
Response: (1) Your point is well made. The SDT can decide whether to submit the elimination of PER-001 and to modify TOP-001 to include the BA. (2) Such a database is not within the scope of the SAR DT, however we will pass this comment on to the NERC staff.	
IESO	Specific to the proposed changes to the standards, we offer the following comments: TOP-001 R2: the SDT suggests to remove this requirement. However, R2 holds TOP responsible for taking immediate actions to alleviate operating emergencies which may be within the TOP area and not monitored by an RC, whereas R3 requires several operating entities to comply with the RC directives. The two requirements serve different purposes. R8: the SDT suggests to delete this requirement. We suggest the SDT to exercise caution and compare this requirement (restoring the system during an emergency) with other related standards to ensure that this is indeed covered elsewhere. TOP-002 R1: the SDT suggests to remove this as it is redundant with TOP-008-1 R1. Please note that TOP-002 R1 requires plans whereas TOP-008 R1 requires TOP to take action in real time. These reuqirements are different. If the SDT wants to revise TOP-002 R1 to eliminate vague requirements, we suggest that the second sentence "In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and systemequipment to implement these plans to ensure that interconnected system reliability will be maintained." be deleted. R3: the SDT suggests deleting R3 as it is redundant with TOP-004-1 R1. We disagree with this proposal. R3 requires the various operating entities to coordinate and develop operational plans; whereas TOP-004-1 requires the TOP to operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs). They are required for different time frames and purposes. R4: the SDT suggests deleting R4 as it is redundant with IRO-005-2, R9. We Disagree with this proposal. Deleting R4 would remove the obligation for BA and Top to coordinate their activities with the RC. Additionally, the two requirements serve different purposes: R4 in TOP-002 serves to ensure that normal Interconnection operation will proceed in an orderly and consistent manner; whereas R9 in IRO-005-2 serves to require the RC to develop and implement action plans to mitigate potential or

Question #9	
Commenter	**Comment**
	actual SOL, IROL, CPS, or DCS violations. R6: the SDT suggests deleting R6 as it is redundant with BAL-002-0 R4 and IRO-005-2 R9. We agree that there is redundancy with BAL-002-0 R4, but we not agree that it is redundant with IRO-005-2 R9. Deleting R6 would remove the obligation for BA and Top to coordinate their activities with the RC. Additionally, the two requirements serve different purposes: R6 in TOP-002 require TOP and BA to plan for contingencies; whereas R9 in IRO-005-2 serves to require the RC to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. R7 and R9: the SDT suggests deleting these requirements as they are redundant with BAL-007 through -011. We do not agree with the deletion of both requirements, due to the fact the standards BAL-007 to BAL-011 have failed the ballot process, and are now part of the Reliability-based Control SAR which is posted for comments. Please see our comments on Q4 (ii), above. R8, R10 and R11: the SDT suggests deleting these requirements as they are redundant with IRO-005-2 R9. We agree with this deletion provided that R4 is retained. Othewise, R10 and R11 should be retained. R18: the SDT suggests to move this to FAC-009-1. We do not agree since the purpose of FAC-009-1 is "To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or Methodologies". We veiw that R18 crosses a number of Standards so there may be a better home than FAC-009-1. TOP-003-0 R3: the SDT suggests deleting R1.3 as it is redundant with IRO-010, R3 as part of the over-all data specification effort. We believe the referenced requirement should be R4. TOP-004-0 R1: the SDT suggests deleting R1 as it is redundant with IRO-009-1, R4. We disagree with this. SAR IRO-009-1 holds the RC responsible for operated within IROL. We feel strongly that the TOP must also operate its system to respect IROL. Further, we need to defer any changes to remove or modify SOL until after the definition of Adequate Level of reliability is defined. We also provided other reasons for retaining it. Please see our comments on Q2, above.

Question #9	
Commenter	**Comment**
	R2: the SDT suggests deleting R2 as it is simply the definition of an IROL and is redundant with FAC-010-1 and FAC-011-1. We disagree with this proposal since R2 requires TOP to operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. FAC-010-1 and FAC-011-1 deal with the methodology to determine SOL and IROL. They hold different entities for doing very different things altogether. R3: We disagree with removing this requirement for the above same reason. TOP-005-1 R2: the SDT suggests deleting this requirment. We agree that R2 is not a reliability requirement, but the SDT needs to recommend a home for entities that receive data from the ISN that it must sign the NERC Confidentiality Agreement for "Electric System Reliability Data". TOP-006-1 R1: the SDT suggests deleting R1 as it is redundant with FAC-009-1, R2. We disagree with this proposal since R1 deals with real-time data such as facility status, resource availability; whereas FAC-009-1 deals with establishing ratings. R4: the SDT suggests deleting R4 as it is redundant with BAL-001 and -002 and is also addressed in IRO-010-1, R1 and R3. We disagree as R4 requires the operating entities to do things that are very different from any of BAL-001, BAL-002 and IRO-010-1. R7: the SDT considers deleting Balancing Authority as it is covered in BAL-005-0, R8 and deleting Reliability Coordinator as it is covered in BAL-008-1, R1. We do not agree with both. In the first case, the requirements for the BA in R7 is to monitor system frequency which is different than those in BAL-005-0, R8 which specify the data and metering requirements. In the second case, BAL-008 doesn't yet exist (falied ballot). TOP-008 R3: the SDT suggests deleting R3 as it is a local utility risk consideration and not a reliability issue as currently worded. We do not agree with the deletion since the requirement implies that the action taken by the TOP has interconnected system implication.
Response: TOP-001-1, R2 comment: You are correct that R2 and R3 address different concepts. However, the drafting	

Question #9	
Commenter	**Comment**
team should have stated that the redundancy was between R1 and R2, rather than R2 and R3. R1 clearly states that the Transmission Operator shall exercise specific authority to alleviate operating emergencies. R2 is largely procedural in nature rather than stating what is to be done. This will be corrected in the re-posted SAR. TOP-001-1, R8 comment: The drafting team agrees. The SDT must include due diligence in comparing various requirements in its consideration of whether to delete R8. TOP-002-2 R1 comment: Your point is understood. The drafting team feels that the TOP has plans in place in order to take the actions required by TOP-008-1 R1. However, the requirement to have plans and the requirement to implement those plans are two different concepts. Your point about deleting the second sentence of TOP-002-2 R1 is a good recommendation. The drafting team will forward your comment to the SDT for its consideration as it makes specific revisions. TOP-002-2, R3 comment: Your statement is correct. The redundancy should reference IRO-004-1, R4, rather than TOP-004-1, R1. TOP-002-2, R7 and R9 comment: At the time the SAR was drafted, the outcome of the BAL-007—011 was not known. The SDT must take this into account as they consider whether to delete R7 and R9. TOP-002-2 R8, R10, and R11 comment: The drafting team agrees that there are complex interrelationships and redundancies throughout the standards. As the SDT considers deleting requirements, they must also watch for these relationships. TOP-002-2, R18 comment: The SAR requires that the SDT consider moving this requirement to FAC-009-1, it does not require that it do so. Part of the methodology required by FAC-009-1 is to include identifiers.	
Manitoba Hydro	Specific to COM-001-1 Telecommunications: In general, we support the proposed revisions to this standard with the following exceptions. Periodicity and type of testing should not be defined explicitly in the standard. The onus must be placed on each organizaton to determine the periodicity and testing requirements as necessary to meet expected performance criteria. Such requirements would require regular review and adjustment to address changing conditions. Appendix B - FERC Order 693: We are concerned that the proposed expansion of the Standard to

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Commenter	**Comment**
	included Generator Operators and Distribution Providers is unachievable within a reasonable period of time relative to ongoing efforts to comply with current standards, i.e., too much too fast. Specific to TOP-005 Operational Reliability Information If the proposed changes are adopted, only one requirement R3 remains in this standard. This requirement involves Balancing Authorities (BAs)and Transmission Operators (TOs) supplying on-line information to associated BAs and TOs for reliability assessments and coordinated operations. This same information is also transmitted to the Reliability Coordinators (RCs)via requirement R1. (which is now to be transferred to and covered by IRO-010-1). If the RCs are receiving all the required reliability data anyway, why can't all concerned BAs and TOs get this same data from the RCs instead of directly from the concerned utility? Won't all BAs and TOs be required to send reliability data the closest RCs, even if they are not already a direct or associate member of any established RC? Keeping TOP-005 only for R3 opens the door to potential reliability analysis and data being developed and transmitted between interconnected BAs and TOs that is NOT also transmitted to RCs. It may be better to make TOP-005 R3. part of another standard (such as IRO-010) to ensure RCs are properly informed, and then eliminate TOP-005 altogether.
Response: COM-001-1 comment: Your comment may apply if there is valid reason for different performance criteria in different organizations. The SAR drafting team will forward your comment to the Standard Drafting Team (SDT) once the SAR is approved, since it deals with a specific treatment of a requirement that the SAR directs the SDT to consider for revision. Appendix B – FERC Order 693 comment: Your concern is noted. However, the drafting teams must address directives of FERC in the revision of standards. You are encouraged to continue your review and to make appropriate comments of each draft of the standard that is posted. TOP-005-1 comments: The purview of the RC may differ from that of the BA and TOP. The RC must have a wider view of the system for which it is responsible and may not analyze down to the “local” level of each BA and TOP system. However, your concepts are interesting and should be part of the activity of the Standards Drafting Team (SDT) when the team is considering the revisions as directed by the SAR.	
MRO	As the standards are revised, it is necessary to insure there is, at a minumim, one measurement for each requirement. If a measure can not be determined for a requirement, the requirement should be rewritten or deleted.
Response: Some measurements may realistically relate to more than one requirement. However, each requirement should	

Question #9	
Commenter	**Comment**
have a measurement which does apply to it. One of the aspects of a good standard requirement is for it to be clear as to what is to be done, by whom, and to what expected result.	
FRCC	The revisions being made under this SAR should be well coordinated with the revisions being made under the Reliability Coordination SAR (Project 2006-06). Both SARs are seeking to revise COM-001 and COM-002. It is also critical that language proposed in the revisions of both projects be well coordinated because of the interrelated nature of the applicable standards.
Response: Each SDT should review related actions of other projects to the extent that the timing allows them to do so. In most cases, each project is revised from a different perspective and conflicting revisions should not occur. This need to coordinate between drafting teams is recognized and the drafting team guidelines caution the drafting teams to keep this in perspective throughout their work.	
IRC SRC	The SAR proposes to add the language "without delay" to a number of requirements. We are concerned that this wording could be interpreted in a standard to require the need for immediate control action. We propose that the standard drafting team should clarify that the "without delay" language does not require immediate control action but requires the applicable entity to begin evaluations necessary to take control actions. These evaluations may include but are not limited to verifying the limit, measurement, or performing a on-line power flow study.
NYISO	The SAR proposes to add the language "without delay" to a number of requirements. We are concerned that this wording could be interpreted in a standard to require the need for immediate control action. We propose that the standard drafting team should clarify that the "without delay" language does not require immediate control action but requires the applicable entity to begin evaluations necessary to take control actions. These evaluations may include but are not limited to verifying the limit, measurement, or performing a on-line power flow study.
Response: The SAR drafting team agrees with your comment. Actions include recognition, investigation, and verification prior to actual control actions. We will pass this comment along to the eventual SDT.	
SOCO Transmission	It is recommended that the drafting team members review all alleged duplications closely to be sure that the true meaning of the duplicated statement is the same as the orginal statement before being deleted. There could be instances where the words are the same but the meaning behind the duplication could be different.
Response: Thank you for your suggestion. The guidelines for the SDT require that they pay close attention to background and content of each requirement considered for revision or retirement.	
WECC RCCWG	The WECC RCCWG suggests differentiating TOP directives from Reliability Coordinator directives. This may be done with specific language. It should be clear to the entity receiving a directive who issued that directive. It may be beneficial to have a NERC definition for a "Reliability Coordinator Directive" and a "Transmission Operator Directive".
Response: The SAR drafting team encourages you to continue to review drafts of standard revisions that the SDT will post	

Question #9	
Commenter	**Comment**
for comment. You may suggest specific changes to specific standard requirements at that time. If there is not an existing standard for which this comment appropriately relates, you may submit a SAR to request the establishment of such requirements.	
City of Tallahassee	None.
Ameren	No comment.
CenterPoint	No comment.
Entergy (Davis)	No comment.
ERCOT	No comment.
PSC SC	No comment.
FirstEnergy	No comment.
HQT	No comment.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on 2nd Draft of SAR for Real-time Transmission Operations and Balancing of Load and Generation (Project 2007-03)

The Real-time Transmission Operations and Balancing of Load and Generation SAR requesters thank all commenters who submitted comments on the first draft of SAR. This SAR was posted for a 30-day public comment period from August 7, 2007 through September 7, 2007. The requesters asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 15 sets of comments, including comments from 46 different people from 30 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, several minor changes were made to the SAR:

- A definitive statement was added to the SAR to clarify that the intent and scope of the SAR was not to remove requirements to monitor and be aware of SOLs.
- As suggested, Generator Owner was added to the list of applicable entities.
- For TOP-002-2: R7, R9, and R12 are no longer marked for possible deletion.
- In COM-002-2, a typo was corrected to point out that the correct reference is to PER-003-1 and not PER-003-0.

The SAR DT feels that these changes are not of a magnitude to require the re-posting of the SAR and is recommending that the SAR be forwarded to the Standards Committee for approval to move on to the standards development process.

It should be noted that there have been opinions expressed that more clarity is needed around SOLs – What are they? Who is responsible? Are they needed at all? While there are commenters who want this SAR DT to address those concerns, this SAR DT stands on its original goal, to remove oversights and problems caused by Version 0, et al. and to revise the resultant set of requirements with respect to the directives in FERC Order 693 and the latest Standard Review Guidelines.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Real-time_Operations_Project_2007-03.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Thad K. Ness	American Electric Power (AEP)	✓				✓	✓				
2.	Jason Shaver	American Transmission Co.	✓									
3.	Paul Bleuss (G3)	CMRC										✓
4.	Greg Tillitson (G3)	CMRC										
5.	Jeanne Kurzynowski (G1)	Consumers Energy			✓	✓						✓
6.	Ed Davis	Entergy Services						✓				
7.	Sam Ciccone	FE FERC Compliance Dept.	✓		✓		✓	✓				
8.	Doug Hohlbaugh	FE FERC Compliance Dept.	✓		✓		✓	✓				
9.	David Folk	FirstEnergy Corp. (FE)	✓		✓		✓	✓				
10.	Roger Champagne	Hydro-Québec TransÉnergie	✓									
11.	Ron Falsetti	IESO		✓								
12.	Kathleen Goodman	ISO New England		✓								
13.	Jim Cyrulewski (G1)	JDRJC Associates								✓		
14.	Eric Ruskamp (G5)	MRO										✓
15.	Joe Knight (G5)	Great River Energy										
16.	Terry Bilke (G5)	MISO										
17.	Mike Brytowski (G5)	MRO										
18.	David Rudolph (G5)	Basin Electric										
19.	Pamela Oreschnick (G5)	Xcel Energy										
20.	Robert Coish (G5)	Manitoba Hydro										
21.	Neal Balu (G5)	WPSR										
22.	Carol Gerou (G5)	Minnesota Power										
23.	Jim Haigh (G5)	WPSA										
24.	Ken Goldsmith (G5)	ALTW										
25.	Tom Mielnik (G5)	MEC										
26.	Craig McLean	Manitoba Hydro	✓		✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
27.	Chris Manchur (G1)	Manitoba Hydro	✓									
28.	Jason L. Marshall (G1)	Midwest ISO Stakeholders		✓								
29.	Rick White	Northeast Utilities	✓									
30.	David L. Gladey	PPL Susquehanna			✓		✓					
31.	Phil Riley (G2)	PSC of SC									✓	
32.	Mignon L. Clyburn (G2)	PSC of SC									✓	
33.	Elizabeth Fleming (G2)	PSC of SC									✓	
34.	G. O'Neal Hamilton (G2)	PSC of SC									✓	
35.	John E. Howard (G2)	PSC of SC									✓	
36.	Randy Mitchell (G2)	PSC of SC									✓	
37.	Robert Moseley (G2)	PSC of SC									✓	
38.	David A. Wright (G2)	PSC of SC									✓	
39.	Thomas J. Bradish	Reliant Energy			✓		✓	✓				
40.	Mike Gentry (G3)	Salt River Project										✓
41.	Marc Butts (G4)	Southern Company Services	✓									
42.	Roman Carter (G4)	Southern Company Services	✓									
43.	Jim Busbin (G4)	Southern Company Services	✓									
44.	J. T. Wood (G4)	Southern Company Services	✓									
45.	Nancy Bellows (G3)	WACM										✓
46.	Barbara Kedrowski (G1)	We Energies					✓					

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – Midwest ISO Stakeholders
G2 – Public Service Commission of South Carolina (PSC SC)
G3 – WECC Reliability Coordination Comments Work Group
G4 – Southern Company Services, Inc. (SOCO)
G5 – Midwest Reliability Organization (MRO)

Index to Questions, Comments, and Responses

1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

Summary Consideration:

The consensus (12 submissions, 65 persons, 21 companies, 31 industry segment representations vs. 5 submissions, 9 persons, 9 companies and 10 industry segment representations) agreed that the scope of the SAR should be expanded to include the three subject IRO standards.

The primary concern voiced in this comment submittal was with the issue of SOLs. It is noted that the SOL issue is not what this SAR was about. This SAR was issued to clarify issues from Version 0, from the ERO regulatory agencies and other cited comments – and to improve the overall quality of the resultant set of requirements and standards.

The current SAR DT is composed of industry experts with long experience regarding the various NERC efforts to attempt to clearly define system limits. However, the current SAR DT does not claim to possess comprehensive knowledge of all of the issues related to SOL issues. We believe that the SOL issue must be addressed directly in a specific SAR effort formed to address it with a larger multi-disciplinary group.

It is clear that more clarity is needed around SOLs – What are they? Who is responsible? Are they needed at all? While there are commenters who want this SAR DT to address those concerns, this SAR DT stands on its original goal, to remove oversights and problems caused by Version 0, et al.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro	☑		Although it is not covered in this SAR's second draft we are assuming from your response to comments on the initial draft that Requirements will remain to ensure that SOLs will be monitored by the RC and TOP and that appropriate action will be taken when SOLs are exceeded. This we agree with.

Manitoba supports expanding the scope.

Response:
Unless changed in the Standards process, IRO-005 R2 would still require that SOLs be monitored; and IRO-005 R17 would still require that SOL violations be corrected.

The SAR DT defines a scope, it can not and does not ensure that a given requirement remains or is deleted. The best the SAR DT can ensure is that an issue in its scope has the opportunity to be addressed.

<table>
<tr><th colspan="4">Question #1</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Northeast Utilities</td><td>☑</td><td></td><td>TOP-001-1 R7.3 Replacing "at the earliest time" with "without delay" is not appropriate, since the step covers "When time does not permit.........". With this change, if there were any delay, it would be a noncompliance.

TOP-007-0 Rewording R2 to say act "without delay", in lieu of "as soon as possible" is not desirable. With this change, if there were any delay, it would be a noncompliance.</td></tr>
<tr><td colspan="4">NE Utilities supports expanding the scope of the SAR.

Response:

This wording should be discussed during the standards process. TOP-001-1 is an exclusion from the prohibition on ‘blindly’ removing facilities from service. The proposal to change the phraseology is suggested to address the issue that the current requirement allows too much leeway in informing the RC of what was done.

TOP-007-0 does require a TOP to act to correct an IROL, and if the TOP does not act - then it is in non-compliance with the standard. The issue raised by the comment has been previously debated. “As soon as possible” was considered too subjective, whereas “without delay” was considered less subjective. The real question is what constitutes “action”. The time associated with evaluating the system is considered (by the writers of the proposal) to be an action. The impetus behind the requirement is that each TOP already has its list of IROL response procedures, and therefore (unless there is a real good reason) the TOP should be implementing those procedures. The underlying ‘evaluation action’ is the time when reasoned adjustments to the plan is expected. One can debate how long the evaluation time should be, and even debate what is an evaluation but no one was able to come up with a standardized performance. It is left to the voters to decide if this is a problem and if it is how to fix the problem.</td></tr>
<tr><td>PPL Susquehanna</td><td>☑</td><td></td><td>IRO-004-1 is applicable to Generator Owners, currently the SAR only list the generator operators. The reliability functions listed in the SAR should be revised to include Generator Owner.</td></tr>
<tr><td colspan="4">PPL Susquehanna supports expanding the scope of the SAR.

Response:
Thank you, the SAR Applicability list will be so amended.</td></tr>
<tr><td>Reliant Energy</td><td>☑</td><td></td><td>In IRO-004-1 Reliability Coodination Operations Planning section 4.6 Generator Owners should be deleted. This standard is also applicable to generator operators as listed in 4.7. The justification for deleting GO is that this reliability standard addresses the</td></tr>
</table>

Question #1			
Commenter	**Yes**	**No**	**Comment**
			operation of a generating facility. The GOP and not the GO would be the entity most knowledgable of equipment capabilities and ratings. The GOP would be the entity conducting and supervising any testing or unit operation required to comply with this standard. The GOP is most likely the entity responsible for maintenance of unit equipment so the GOP would be most familiar with equipment limits, ratings and capabilities. In addition, replacing GO with GOP in this standard and other standards has the following benefits: 1. How a facility is operated has more impact on reliability than ownership of a facility. 2. Removing the GO from responsibility will more clearly define who is responsible for standard compliance at jointly-owned facilities. 3. For jointly-owned facilities, this change eliminates the need for each owner to make redundant submittals and streamlines administration for each Regional Entity. 4. As the industry moves away from the regulated model, more non-traditional entities will become owners of facilities. These owners typically contract operation responsibilities to entities with operating experience. The operating entity will more fully understand the importance of reliability and would be in a better position to comply. 5. Requiring the GO to be responsible for standard compliance may in some cases discourage non-traditional entities from owning generating assets, which will hinder competition in the market.

Reliant supports expanding the scope of the SAR

Response:
The scope of this SAR with regard to IRO-004 is to simply eliminate redundancies within that standard for the TOP. We suggest that you should submit these comments to the SDT dealing with specific changes to the IRO requirements.

1. The line of reasoning for obligating an Owner for providing 'unit ratings' is as follows: The Owner has the inherent right (as the owner of the facility) to rate that facility in any way the owner sees fit. On the other hand, the Operator of the asset can be a third party that must respect the owner's boundaries and still work within the constraints of the BES. The Operator has the right / obligation to use the Owner's rating to stay within the reliability constraints of the BES. The Operator may further constrain a units operation, but should not (without the owner's permission) violate the Owner's imposed unit rating.

2. The asset belongs to the Owner, and the Owner's risk management should be respected.

3. This is a legal / contractual issue not a NERC issue.

<table>
<tr><th colspan="4">Question #1</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">4. This is a legal / contractual issue not a NERC issue.

5. This is an opinion / projection that is outside NERC / the SAR DT concerns.</td></tr>
<tr><td>American Electric Power</td><td>☑</td><td></td><td>We agree with the concept of eliminating redundancy in the NERC Standards. However, Project 2006-08 involves re-writing IRO-006 in three phases and is currently in phase one. Any changes required to IRO-006 to eliminate redundancy of Transmission Operator and Balancing Authority requirements in other standards should be coordinated with, and handed off to, the Project 2006-08 IRO-006 Standard Drafting Team. Thus, IRO-006 should not be included in the scope of this SAR. We have no objection to including IRO-004 and IRO-005 into the scope of this project and we stand by our comments to the first SAR.</td></tr>
<tr><td colspan="4">AEP supports expanding the SAR for IRO-004 and 005.

Response:
IRO-006
The SAR DT recognizes that there is a need for coordination among different NERC Projects but it is the Standards DT that has the responsibility for coordinating any changes that the Industry approves, and to coordinate them with other Projects (in coordination with the NERC Standards Manager and the NERC Standards Committee). Project 2006-08 is designed to focus on the TLR process. The SAR DT is focused on responding to previous unanswered comments; and in identifying and eliminating redundancies.</td></tr>
<tr><td>Entergy</td><td>☑</td><td></td><td>We have additional comments on other parts of this revised SAR.

COMMENTS ON TOP-001-1

We suggest the deletion of the first recommended change to TOP-001-1:

o Removal of R2 due to redundancy with R1. R2 largely describes an ill-defined procedure which should not be in a standard.

This suggested change was revised from the first posting of this SAR, changing "with R3" to "with R1". Each of the three requirements of TOP-001-1 address different</td></tr>
</table>

Question #1			
Commenter	**Yes**	**No**	**Comment**
			responsibilities of a TOP. R1 states a TOP has responsibility and authority, R2 states the TOP will take action, and R3 states the TOP and others will comply with the directives of the RC, or TOP. We do not agree R2 contains an ill-defined procedure. However, we may agree to remove TOP-001-1 R2 because it may be redundant with TOP-008-1 R1. We also suggest revising the TOP-001-1 draft change from: - Eliminating R5 in light of possible redundancy with IROL standards. to: - Eliminating R5 IF REDUNDANT with IROL standards. COMMENTS ON TOP-002-2 The first suggestion of TOP-002-2 suggests deleting R1 as it is redundant with TOP-008-1 R1. We recommend changing the TOP-008-1 reference to R2, rather than R1. We agree that TOP-002-2 can be eliminated as being redundant with TOP-008-1 R2, not TOP-008-1 R1. We do not agree with the suggestion that TOP-002-2 that R4 should be deleted. TOP-002-2 R4 is a requirement on the BA and TOP while IRO-005-2 R9 is a requirement on the RC. We do not agree with the suggestion of deleting TOP-002-2 R6 as it is redundant with IRO-005-2 R9. However, we do agree with deleting R6 if the reason is changed to being redundant with EOP-001 R3.2. With this change we agree with deleting TOP-002-2 R6. We do not agree with the suggestion to delete TOP-002-2 R7 and R9. Both these requirements should remain in TOP-002. The reason for the suggested deletion is R7 and R9 are redundant with BAL-007 through BAL-011. However, BAL-007 through BAL-011 were not approved by the Ballot Body and are not NERC standards. Therefore TOP-002-2 R7 and R9 are not redundant and the suggestion should be deleted. TOP-002-2 R12 should not be deleted. We believe it is not redudant of the requirements in FAC-010 SOL Methodology for the Planning Horizon and FAC-011 SOL Methodology for the Operations Horizon.

Question #1			
Commenter	**Yes**	**No**	**Comment**
			COMMENTS ON TOP-004-1 The first entry for TOP-004-1 suggests deleting reference to SOL in R1. Deleting R1 indicates TOPs are not required to operate within SOLs. TOPs should operate within SOLs and this entry should be deleted from the SAR. COMMENTS ON TOP-005-1 It is suggested deleting R1 and R1.1 as they are redundant with IRO-010-1. However, IRO-010-1 is not an approved standard so R1 and R1.1 should remain in TOP-005-1. That is unless the SAR is changed to say R1 and R1.1 should be deleted after IRO-010-1 is approved and has provisions that duplicte R1 and R1.1. It is suggested that R4 be deleted from TOP-005-1. Do not delete R4 (PSE provides information as requested for reliability assessments and coordinate operations) as it is significantly more encompassing than INT-001-2 R1 (which only requires PSEs provide Arranged Interchange to the IA.) If anything is done INT-001-2 R1 should be deleted and TOP-005-1 R4 should be kept. COMMENTS ON TOP-006-1 It is suggested that R1 be deleted from TOP-006-1. Do not delete R1 (report facility status) as it is significantly different than FAC-009-1 R2 (report facility ratings). They are not the same. It is suggested that R4 be deleted from TOP-006-1 as the requriement is redundant with BAL-001 and -002 and is addressed in IRO-010 R1 and R3. R4 should only be deleted if the requirements are actually included in the final approved IRO-010. It is suggested that R6 (use sufficient metering) be deleted from TOP-006-1 as the requirement is redundant with BAL-005-1 (annually check and calibrate time error and frequency devices). We suggest R6 be kept in TOP-006-1 since the requirements are not in BAL-005-1. COMMENTS ON TOP-007-0

Question #1			
Commenter	**Yes**	**No**	**Comment**
			It is suggested to delete R4 in deference to the RC Project. We suggest R4 be kept in TOP-007-0 until the RC Project is a NERC approved standard. COMMENTS ON TOP-008-0 It is suggested to delete R1 (relieve IROL or SOL) as it is redundant with TOP-007-0 R3 (relieve IROL). We suggest R1 be kept in TOP-008-0 or include SOLs in TOP-007-0 R3. COMMENTS ON COM-001-1 No Comments. COMMENTS ON COM-002-2 The first bullet is to delete the second sentence of COM-002-2 R1 as it is redundant with PER-003-0 R3. However, there is no R3 in PER-003-0 so we recommend the second sentence stay in COM-002-2 R1.

Entergy agrees with expanding the scope of the SAR.

Response:

1. **TOP-001-1**: Entergy and the DT both agree with the removal of **R2**; but Entergy disagrees with the rationale provided. The purpose of the SAR DT is to provide a scope for a Standard DT. The SAR DT's rationale is provided to help understand the DT's justification, the rationale is not provided for approval or inclusion in the standard. This reply also applies to the comment for **R5**. Entergy approves considering **R5** for removal, but does not agree with the justification. The words used in the request's justification are not under debate. The debate is whether or not to keep the item in scope.

2. **TOP-002-2**: Entergy and the DT both agree with the removal of **R1**; but Entergy disagrees with the rationale provided. The issue that must be resolved is whether or not it is sufficient that a NERC standard hold one entity responsible for coordinating a given task, or should every entity be assigned partial responsibility. This requirement is therefore included within scope and will best be debated in the Standards Development process.
   We both agree with the removal of **R6**; but Entergy disagrees with the rationale provided.

   You are correct that BAL-007 – 011 have not been approved and therefore R7 and R8 can not be held redundant.

Question #1			
Commenter	Yes	No	Comment

However, this does not remove TOP-002-2 from the scope of the SAR.

You are correct that R12 is not redundant with the FAC-010 & 011 standards. The elimination of this requirement does not materially affect the scope of the request, as TOP-002 will still remain in scope.

3. **TOP-004-1**: The commenter stated that removing R1 of TOP-004 will remove the obligation of TOPs from operating within SOLs. The SAR DT notes that IRO-005 R17 properly places the responsibility on the RC who in turn has the authority to require the TOP to act. The debate is best carried out by the Industry in the standards process not in the scoping phase. If the Industry agrees that the responsibility is on the RC and that a requirement on the TOPs is unnecessary then the requirements on the TOPs will be removed. If the Industry agrees that there is a separate need for TOPs to have a standard requirement on them, then the requirement will be retained. Either way there is a need for the issue to be discussed.

4. **TOP-005-1**: The commenter is correct that the observed redundancy for R1 and R1.1 is predicated on a non-approved standard. The SAR DT agrees that any Industry-approved changes should / must be coordinated with the other BOT-approved standards in place at the time the new modifications are to be implemented.

   The commenter is correct that TOP-005-1 R4 is more inclusive then INT-001-2 R1. The SAR DT's intent was to delete one of the two. The decision of which if any of the two requirements to retain, modify or delete is to be decided by the industry.

5. **TOP-006-1:** The commenter is correct that the data requirements of TOP-006-1 R1 (unit availability) is different from the data requirements of FAC-009-1 R2 (unit capability / rating).

   Regarding R4 the SAR DT agrees that any Industry-approved changes should / must be coordinated with the other BOT-approved standards in place at the time the new modifications are to be implemented.

   The commenter is correct that R6 (sufficient metering) is different from BAL-005-1 (calibration).

   TOP-007-0: Regarding R4, the SAR DT agrees with Entergy that any Industry-approved changes should / must be coordinated with the other BOT-approved standards in place at the time the new modifications are to be implemented.

6. **TOP-008-0:** The debate over SOL/IROL is best carried out by the Industry in the standards process not in the scoping phase. If the Industry agrees that the responsibility is on the RC and that a requirement on the TOPs is unnecessary then the requirements on the TOPs will be removed. If the Industry agrees that there is a separate need for TOPs to have a standard requirement on them, then the requirement will be retained. Either way there is a need for the issue to be

Question #1			
Commenter	**Yes**	**No**	**Comment**
			discussed. 7. The redundancy is between PER-003-1 (not PER-003-0) R3 and COM-002-2 R1.
FirstEnergy Corp.	☑		FirstEnergy, like some other entities, is concerned that the SAR drafting team did not provide an opportunity to comment on their proposed resolution to the SOL issue identified in Question 2 of the previous draft's comment form. While it is not crystal clear to us that the SAR Drafting Team intended to removal all references to SOLs from the Standards, it is also not clear to us that the revisions made to the SAR by the drafting team adequately addressed the views expressed by the commenters. The messages sent by the SAR Drafting Team in the Comment Summary and the individual responses to comments seem mixed. The response to comments document indicates that the SAR drafting team will pass comments on to the Standard Drafting Team; however, the modifications to the SAR were minor and did not provide any guideance to the Standard Drafting Team on the method for applying these comments. Furthermore, the SAR Drafting Team did not seem to embrace the comments provided by the industry on this topic. We understand that the comments received were provided by a small segment of the industry; however, we are also aware that the communication from the commenters was was clear. The majority of commenters supported the retention of SOLs in the standards as necessary and appropriate. All of this being said, while we clearly do not agree with the wholesale removal of SOLs from the Standards, but we do support the removal of SOLs from TOP-004-1 Requirement 1 as specified in the SAR. We support this because the methodology used to determine SOLs, and for that matter, IROLs is not clearly defined. This means that one organization may be using a methodology that produces an eight hour SOL while another's method may produce a one hour SOL. We believe that the company using an eight hour limit should not be bound as tightly to that limit as a company that uses a one hour limit. Therefore, the SAR should direct the Standard Drafting team to develop, or at least investigate the development, of a limit methodology applicable across all of NERC that can be consistently applied. FE also offers the following comments to specific items revised in the SAR: Added IRO-004, IRO-005 & IRO-006 to the scope of the standards to be reviewed to eliminate redundant requirements. FE agrees

Question #1			
Commenter	**Yes**	**No**	**Comment**
			Clarified that the reason for recommending the deletion of TOP-002-2, R8 is because the requirement is unmeasurable. R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency. FE disagrees with this direction. There does not appear to be an industry agreed upon justification given to remove this requirement in lieu of developing 'R8' along with eliminating ambiguity in the existing measure for this requirement described in 'M3'. Removed the recommendation for deleting TOP-002-2, R11: R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator. FE agrees Reworded the recommendation in TOP-002-2, R14 & R15 to clarify that these requirements may be better addressed in other standards. R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but no limited to: R14.1. Changes in real output capabilities R15. Generator Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output). FE agrees, but with the following provision: The SDT should also develop clear justification for addressing these requirements in "other standards" while identifying the appropriate "other standards"; and, if justified, the SDT should develop a clear, industry approved plan to transfer these requirements to those identified standards.

<table>
<tr><th colspan="4">Question #1</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>Clarified the deletion requested in TOP-004-1, R1 is the reference to 'SOLs'
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
FE agrees, but with the following provision:

The SDT should also consider verbiage in the standards with regard to how SOLs can still be conveyed with some indirect measure (non-sanctioned) of importance in development of the applicable standards.</td></tr>
<tr><td colspan="4">FE agrees that IRO-004, 005 and 006 should be included in the scope of the SAR to eliminate redundancies

Response:
TOP-002-2
The debate regarding the removal of given requirements will be part of the standards development process (not the SAR process). The direction and philosophy of the Industry will be decided by the comments and responses to the standards. The Industry will decide whether or not to retain TOP-002-2 R8. The comments and responses will decide whether or not the measures associated with are appropriate. The question is whether or not to have the debate, and your response shows that there is such a need.

The SAR DT recognizes the need for coordination among standards. However, the SAR DT has the responsibility for defining the scope, it does not have the responsibility or the power to develop an implementation scheme for changes that have not yet been identified let alone approved. It is the Standards DT responsibility to coordinate the implementation of any changes that the industry approves during the standards development phase of the process.

TOP-004-1
The issue of SOL definition and requirements will be dictated by what requirements and standards are approved by the Industry.</td></tr>
<tr><td>PS Commission of South Carolina</td><td>☑</td><td></td><td></td></tr>
<tr><td>Southern Company</td><td>☑</td><td></td><td></td></tr>
<tr><td>WECC Reliability Coordination Comments Work</td><td>☑</td><td></td><td></td></tr>
</table>

Question #1			
Commenter	**Yes**	**No**	**Comment**
Group			
Response: The RTO SAR DT thanks you for your support.			
IESO	☑	☑	Since this comment form has only one question, we are checking both boxes - yes for inclusion of IRO-004, -005 and -006 but no to some of the changes made or not made to the previous SAR, and provide additional comments as follows: (1) Specific to the bullets provided in the background section, above, we agree with the first bullet and do not have any comments on the 2nd to 4th bullets. However, we do not agree with the 5th bullet to remove reference to SOL from TOP-004-1 R1, which requires that "Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs)." In the SAR DT's response posted in Consideration of Comments, it states that "Based on stakeholder comments, the SAR DT is proposing to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs." Removing reference to SOL in TOP-004-1 R1 contradicts with the above statement. Further, we continue to strongly disagree with the SDT that TOPs are not required to operate within SOLs - We agree that all SOLs are not created equally but there are those SOLs which have a tremendous impact on system reliability, much in the same way as IROLs, and given the appropriate conditions, these very SOLs, if not complied with, could have a highly detrimental impact on the system and subsequntly the interconnection (also see comments by others in the Consideration of Comments). (2) In the Consideration for Comments, the SAR DT responded to our previous comments under Question #9, from TOP-001 R2 to TOP-002 R18. We appreciate that the DT's concurs with most of our comments. However, we are unable to find the DT's response to our other comments, from TOP-003 to TOP-008. A review of the revised SAR indicates that changes proposed in the previous SAR for these standards/requirements would remain, some of which we expressed disagreement in our previous comment submission. Not seeing a response from the SAR DT, we are uncertain whether our comments were overlooked, or the DT concluded that our comments did not result in any material changes to the proposed revisions to these

Question #1			
Commenter	Yes	No	Comment
			standards. Assuming it was an oversight, we are providing our comments on TOP-003 to TOP-008 again as follows. We would appreciate seeing the DT's response to these comments when the Consideration of Comments on this revised SAR is posted. TOP-003-0 R3: the SDT suggests deleting R1.3 as it is redundant with IRO-010, R3 as part of the over-all data specification effort. We believe the referenced requirement should be R4. TOP-004-0 R1: the SDT suggests deleting R1 as it is redundant with IRO-009-1, R4. We disagree with this. SAR IRO-009-1 holds the RC responsible for operated within IROL. We feel strongly that the TOP must also operate its system to respect IROL. Further, we need to defer any changes to remove or modify SOL until after the definition of Adequate Level of reliability is defined. We also provided other reasons for retaining it. Please see our comments on Q2, above. R2: the SDT suggests deleting R2 as it is simply the definition of an IROL and is redundant with FAC-010-1 and FAC-011-1. We disagree with this proposal since R2 requires TOP to operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. FAC-010-1 and FAC-011-1 deal with the methodology to determine SOL and IROL. They hold different entities for doing very different things altogether. R3: We disagree with removing this requirement for the above same reason. TOP-005-1 R2: the SDT suggests deleting this requirement. We agree that R2 is not a reliability requirement, but the SDT needs to recommend a home for entities that receive data from the ISN that it must sign the NERC Confidentiality Agreement for “Electric System Reliability Data".

Question #1			
Commenter	**Yes**	**No**	**Comment**
			TOP-006-1 R1: the SDT suggests deleting R1 as it is redundant with FAC-009-1, R2. We disagree with this proposal since R1 deals with real-time data such as facility status, resource availability; whereas FAC-009-1 deals with establishing ratings. R4: the SDT suggests deleting R4 as it is redundant with BAL-001 and -002 and is also addressed in IRO-010-1, R1 and R3. We disagree as R4 requires the operating entities to do things that are very different from any of BAL-001, BAL-002 and IRO-010-1. R7: the SDT considers deleting Balancing Authority as it is covered in BAL-005-0, R8 and deleting Reliability Coordinator as it is covered in BAL-008-1, R1. We do not agree with both. In the first case, the requirements for the BA in R7 is to monitor system frequency which is different than those in BAL-005-0, R8 which specify the data and metering requirements. In the second case, BAL-008 doesn't yet exist (failed ballot). TOP-008 R3: the SDT suggests deleting R3 as it is a local utility risk consideration and not a reliability issue as currently worded. We do not agree with the deletion since the requirement implies that the action taken by the TOP has interconnected system implication.

IESO supports expanding the scope of the SAR.

Response:

The IESO requests a comprehensive debate on SOLs, and that requires an independent SAR. The proposal to change TOP-004 would eliminate the immediate conflict and allow NERC to have a standard that all entities agree with (i.e. everyone agrees that TOPs should operate within IROLs.) while leaving the debate on SOLs for another SAR. As such the decision would be made by the voters and not by the SAR DT. The concern among some is with the fact that System Operating Limits are not "in every case" adhered to (or needed to be adhered to) – as IESO notes in its comments "not all SOLs are created equal." TOPs often make use of multiple System Operating limits (instantaneous, short term and longer term limits). Exceeding a given limit while respecting a shorter time limit is an everyday occurrence. When is the TOP non-compliant? To which value? IROLs on the other hand are not viewed in the standards in the same way as SOLs. The IROL standards go as far as to require proactive operations before the limit is violated.

Question #1			
Commenter	Yes	No	Comment

The SAR DT did not see a contradiction in retaining requirements to monitor SOLs because although it is not uncommon to exceed some SOLs, it is still important to know what is happening on the system. By leaving the monitoring to RCs, the standards ensure that someone is watching out for 'reliability' but not necessarily for a precise limit compliance. RCs must be aware of those SOLs that do "have a tremendous impact". But unless and until there is a better definition of SOL, it will be impossible to separate which SOLs require compliance and which SOLs do not.

TOP-003-0
IRO-010-1 (dated March 8, 2007) does not have an R4. The SDT reference to R3 (which states that everyone must provide data to the RC) is a good replacement for the prescriptive TOP-003-0 R1.3 (which fixes times of day). Indeed one could argue that such timing requirements belong to NAESB not NERC.

The SAR DT does recognize that IRO-010-1 has not been approved. Therefore the Standards DT must consider that any Industry-approved changes should / must be coordinated with the other BOT-approved standards in place at the time the new modifications are to be implemented.

TOP-004-0
The SAR DT interprets R1 (having the RC and TOP both responsible for the same IROL) as redundant and suggests that the Industry consider formalizing the requestor's view. IESO asks that this debate not be raised. The SAR DT believes that it should be discussed. The SAR DT merely keeps this issue in its scope; the voters will decide the merit of that view.

R2 follows the same logic as R1. The SAR DT believes that the issue of whether or not RC and TOP having identical responsibilities is redundant is an issue that they want in their SAR.

R3 – The debate between RC and TOP not withstanding, this requirement must be kept within scope, if for no other reason then the fact that both FERC and NERC require removal of all references to RRO.

TOP-005-1
The SAR DT is not responsible for finding a home for the ISN. IESO agrees that the current requirement "is not a reliability requirement". IESO has not provided any justification for its position that the SAR DT has that obligation.

TOP-006-1
IESO is correct that the data requirements of TOP-006-1 R1 (unit availability) are different from the data requirements of FAC-009-1 R2 (unit capability / rating).

Contrary to the IESO statement, R4 requires does not require operating entities to do anything; R4 requires them to have

Question #1			
Commenter	**Yes**	**No**	**Comment**
data to predict "near-term load patterns". The SAR DT original comment was based on the concept that the real objective of load forecasting is system control. Hence whether or not an entity has data, the BAL standards require them to control the system. Of course near-term load forecasting is used in other areas of operation (e.g. unit commitment); the fact is that R4 is considered by some as being meaningless as a standard. As long as the entities have access to the internet they will have information to predict load. R7: The SAR DT does recognize that BAL-008 & 009 were not approved, but is also aware that they are under active reconsideration. R7 requires monitoring of frequency. The issue of redundancy arises from the fact that BA-005 requires BA have the information to compute ACE, and by definition ACE includes frequency, ergo, the BA is for all practical purposes monitoring frequency. Even if BAL-008 doesn't pass again, the RC is responsible for reliability (real power, reactive power, voltage and frequency). It makes no sense to have a standard for each item that must be monitored. Common sense must be applied to the standards. **TOP-008** See first two paragraphs of Response.			
MRO	☑	☑	If the SAR Drafting team feels that the Standard Drafting Team can handle three additional standards the MRO has no issue with including them in the scope. Additional comments: It has come to our attention that TOP-001-1 R3 is an exact duplicate of IRO-001-1 R8. Of theses two instances, it seems most appropriate to remove the Requirement in IRO-001-1 as that standard is focused on the responsibilities and authorities of the Reliability Coordinator. The MRO recommends either including this in the scope of this SAR or adding this comment to the future work of the IRO-001-1 standard. R8 in TOP-002-2 should not be eliminated because it is not measurable. The SDT should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible, deletion would then be appropriate. It would seem more appropriate for the SDT to make this determination rather than the SAR DT. Because the SAR states that R14 and R15 in TOP-002-2 may be better addressed in

Question #1			
Commenter	Yes	No	Comment
			other standards, we are concerned that the standards drafting team may delete these requirements under the assumption that another team will add them to another standard. This standard drafting team should not remove these requirements unless they simply are not needed for reliability or are added to another standard in conjunction with the deletion. The MRO members are also confused on the SOL issue. In the Consideration of Comments to SAR 1 question #2, the SAR DT asked the if it would be appropriate to remove all requirements related to SOLs from the NERC Reliability Standards. 5 groups of commenters agreed with removing SOLs, 9 disagreed and 5 abstained. The SAR DT concluded that they would propose to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs, yet nothing was changed in the scope of this SAR to reflect that decision. It would have been advantageous to request comments on the new direction proposed by the SAR DT on SOLs as it was heavily commented on during the last round of comments. Also it appears that all SOL are not crated equal, see the discussion below discussing potential SOL issues. To the extent that an SOL is truly local (i.e. radial load serving line), there is no need for the SOL requirements. However, there are SOLs that may not pose a transmission security problem but could impose a generation adequacy problem on another system if the equipment should become damaged. Imports into another system may then be reduced. Additionally, multiple SOLs occuring on a system may be a sign of an undetected IROL. Clearly there should be an obligation on the part of the TOP and RC to review the situation to rule it out.

MRO supports expanding the scope of the SAR.

Response:

Both TOP-001 and TOP-002 are included in the scope of this SAR, and MRO will have the opportunity to be involved in what is or isn't included in those standard.

Regarding the issue of SOLs, the SAR DT did not and does not intend to include a complete discussion of all the issues that must be debated on that topic. The SAR DT agrees with MRO that not all SOLs are created equal, and that is the reason the DT is proposing within this Project to, as much as possible, focus on IROLs.

To eliminate confusion, MRO may desire to submit its own SAR regarding how to address SOLs.

Question #1			
Commenter	**Yes**	**No**	**Comment**
ISO New England **NY ISO**		☑	Both IRO-006-3 and draft IRO-006-4 have the TOP listed in applicability section. However, neither actually has any requirement in the standard. They simply reference the TOP in the requirements. Because there is not the typical question regarding additional comments in the comment form, we will provide those here. R8 in TOP-002-2 should not be eliminated because it is not measurable. The standards drafting should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible deletion may be appropriate, but the industy, not the SAR drafting team, should not be making this determination. Because the SAR states that R14 and R15 in TOP-002-2 may be better addressed in other standards, we are concerned that the standards drafting team may delete these requirements under the assumption that another team will add them to another standard. This standard drafting team should not remove these requirements unless they simply are not needed for reliability or added to another standard in conjunction with the deletion. The SAR drafting team should modify the scope so that all requirements to monitor and control flows within SOLs are not eliminated. While the SAR drafting team points out in their response to the comments that NERC's definition defines an SOL as local, eliminating all requirements to monitor and control to SOLs will be detrimental to reliability. Multiple SOLs occuring on a system may be a sign of an undetected IROL or, if left unchecked, propagate into an IROL. This was the cause of the August 14th blackout. Clearly there should be an obligation on the part of the TOP and RC to monitor and mitigate these limits to prevent such propagation.
ISO NE & NYISO do not support expansion of the scope of the SAR. **Response:** **IRO-006** The commenter is correct that the TOP is not in IRO-006. **TOP-002-2** The debate regarding the removal of given requirements will be part of the standards development process. The direction and			

Question #1			
Commenter	**Yes**	**No**	**Comment**
philosophy of the Industry will be decided by the comments and responses to the standards. The Industry will decide whether or not to retain TOP-002-2 **R8**. The comments and responses will decide whether or not the measures associated with are appropriate. The question posed by the DT is whether or not to have the debate, and your comments show that there is such a need. Regarding R14 and R15, the SAR DT does not add or remove anything; and in fact the Standards Drafting Team does not add or remove anything. The voters decide what gets included and what gets excluded. The SAR DT has proposed a scope of standards to be addressed for the purpose of eliminating redundancies and removing non-standards. The voters decide which standards / requirements get modified or changed. **SOLs** The issue of whether or not there is a need for a standard that SOLs should be monitored is proposed. If the voters agree they will eliminate the requirement and if they want to keep it they will retain the requirements. The SAR DT wants to have the debate whether or not NY and NE agree, SARs are scoping documents designed to request changes. Once approved the SAR is the starting point for debates on issues identified by the SAR drafter. NY and NE must participate in the standards process to make their point, rather than avoid the impending required debate.			
MISO Stakeholders		☑	We are concerned that the SAR drafting team did not provide an opportunity to comment on their proposed resolution to the SOL issue identified in Question 2 of the previous draft's comment form. It appears that the drafting team did not adequately address the view expressed by the majority of the commenters. We draw this conclusion from the inconsistency in the determination of what is a consensus and what isn't. For example, the comment form shows that the SAR drafting team wrote: "The SAR drafting team appreciates that the industry is near consensus," in response to comments on Question 1. There were 13 yes votes in support, 6 no votes against and 4 abstentions. In response to question 7, the SAR drafting team wrote: "The consensus is that the industry agrees with the stated purpose of the SAR." There were 14 yes votes indicating support, nine no votes indicating disagreement and no abstentions. Question 2 asked if the commenter agreed that SOLs should be moved into guides or good utility practices. 13 commenters voted no, 6 voted yes and 7 abstained. Given that the drafting team found near consensus on question 1 and consensus on question 7, we question why the drafting team does not view the responses to question 2 as a consensus? We are further troubled by the drafting team's solution to this SOL issue. In the responses, the SAR DT proposes to retain requirements to be aware of SOLs and monitor system conditions related to SOLs. However, there is actually no scope changes that

Question #1			
Commenter	**Yes**	**No**	**Comment**
			reflect this response in draft 2 of the SAR. Addtionally, the drafting team asked only one specific question in the comment form for draft 2. It is unusual to not add the general open ended question that allows the commenter to provide any additional comments. We find this unusual given that the drafting team chose the word propose in their response. Use of this word would tend to invite a response because one is not sure that the proposal is acceptable. If the drafting team had an expectation that the proposal may not be acceptable, why would they not ask if the proposal is acceptable in the comment form? We believe they should have asked specifically if the proposed solution would "bridge the divide" between the commenters and the drafting team. Clearly they are on opposite ends of a spectrum with the SOL issue and one would think it would be prudent to determine if the gap has been narrowed enough before moving on to the standards drafting phase. We also believe that the SAR DT did not follow the Reliability Standards Development Procedure. On page 16, under step 2 is the following paragraph: "The requester, assisted by the SAR drafting team if one is appointed, shall give prompt consideration to written views and objections of all participants. An effort to resolve all expressed objections shall be made and each objector shall be advised of the disposition of the objection and the reasons therefore." It would appear that the SAR DT did not fully resolve expressed objections with removal of SOL requirements and should continue working to do so. We also have the following specific issues with the SAR. R8 in TOP-002-2 should not be eliminated because it is not measurable. The standards drafting team should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible, deletion would then be appropriate. The SAR drafting team should not be making this determination. Because the SAR states that R14 and R15 in TOP-002-2 may be better addressed in other standards, we are concerned that the standards drafting team may delete these requirements under the assumption that another team will add them to another standard. This standard drafting team should not remove these requirements unless

Question #1			
Commenter	**Yes**	**No**	**Comment**
			they simply are not needed for reliability or are added to another standard in conjunction with the deletion. The SAR drafting team should modify the scope so that all requirements to monitor and control flows within SOLs are not eliminated. While the SAR drafting team points out in their response to the comments that NERC's definition defines an SOL as local, eliminating all requirements to monitor and control to SOLs will be detrimental to reliability. To the extent that an SOL is truly local (i.e. radial load serving line), there is no need for this requirement. However, there are SOLs that may not pose a transmission security problem but could impose a generation adequacy problem on another system if the equipment should become damaged. Imports into another system may then be reduced. Additionally, multiple SOLs occuring on a system may be a sign of an undetected IROL. Clearly there should be an obligation on the part of the TOP and RC to review the situation to rule it out.

MISO does not support expanding the scope of the SAR.

Response:

If MISO Stakeholders believes that there was a blatant disregard for the process they can file a complaint with the NERC Standards Committee.

MISO Stakeholders should not be troubled by the SAR DT's "solution" to the SOL issue, because the SAR DT did not provide a solution – they provided a scope of work to address prior industry questions to reduce / eliminate redundancies. If MISO Stakeholders would like to propose SOL standards, again they are free to draft a SAR on SOLs. This was not an SOL SAR.

TOP-002-2:
MISO Stakeholders proposes that the Standards DT (not the SAR DT) decide on whether or not to keep R8. The SAR DT thanks MISO Stakeholders for their agreement to keep this requirement within scope.

Regarding **R14** and **R15** MISO Stakeholders has a position that they want to effect. That is a legitimate position, but the SAR DT cannot ensure that the MISO Stakeholders position will be agreed to in the standards process. MISO Stakeholders has the misconception that the Standards DT will write the final requirements. The Standards DT will not remove any requirements unless the industry approves of removing those requirements.

Regarding monitoring requirements, MISO Stakeholders has a position on the requirements and they ask that the SAR DT protect that position. It is not the responsibility of the DT to protect a given company's position. This SAR is a scoping

Question #1			
Commenter	**Yes**	**No**	**Comment**
document not a process to ensure any one position. The idea of protecting equipment from damage is a laudable goal but it is not a goal of this SAR. To be a goal of a standard, the term Equipment damage would need to be defined. This DT does not include that concern in its purpose. Regarding Generation adequacy, that is outside the purpose of this SAR. Adequacy will be dealt with in a separate SAR. Here again, there is no reason MISO Stakeholders can not submit its own SAR to address this concern.			
American Transmission Co.		☑	The SDT has not provided any information as to scope of work that will be performed on IRO-004, 005 and 006 in the posted version of the SAR. Therefore ATC does not agree with the expanded scope. The SAR SDT must provide information as to why these standards must be worked on as part of this effort. We request that the SAR SDT provided the necessary information and post a revised version of the SAR for comment. Additional comments: Issue 1: A majority of comments submitted on Question 2 (Initial SAR posting) did not support the SDT proposal to remove SOL requirements from NERC's Reliability Standards. ATC believes that SOLs are a BES issue and must continue to be part of NERC Reliability Standards. ATC does not agree with the SDT proposed compromise that would limit Reliability Standards to only requiring monitoring of SOL. (Note: The SAR provides little to no justification as to why SOL should be removed from NERC Reliability Standards.) "Question 2 (initial SAR posting): The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on 'good utility practice'. Do you agree?" Issue 2: ATC continues to disagree with the current scope of work. We find that scope of work's description is overly prescriptive and not complete. It seems that the SAR is attempting to remove requirements that address SOL conditions from NERC standards but that is never specifically stated in the SAR. It's also import to note that in Appendix B of the SAR no specific request was made to remove SOL from NERC standards. Many of the requests in Appendix B only support clarification and removal of redundant

Question #1			
Commenter	**Yes**	**No**	**Comment**
			requirements. It's our position that the effort to remove SOLs from NERC standards will reduce interconnection reliability. Therefore ATC can not support this SAR until a proper scope of work is developed. The scope should be limited to clarifying existing requirements by; removing redundancy, better alignments of requirements to measures and removal/clarification of ambiguous language. Issue 2a: COM-001 Is currently being worked on in projects 2006-04 & 2006-06 COM-002 Is currently being worked on in projects 2006-06 & 2007-02 IRO-004 Is currently being worked on in project 2007-02 IRO-005 Is currently being worked on in project 2007-02 & 2007-18 IRO-006 Is currently being worked on in project 2006-08 Lastly ATC believes that this project should be delayed until the all previously identified efforts have been completed in order to insure an efficient work flow. If this project is moved into the standard development phase five Standards will have parallel efforts on going. Coordination will be extremely difficult if not impossible to manage.

ATC does not support expanding the scope.

Response:

ATC requests a response to why the SAR DT asked to include the subject three standards. Answer: In reviewing a comment received during the last round of comments, it was brought to the DT's attention that there were redundancies in IRO004, 005 and 006. In order to address those redundancies it was necessary to ask the industry if the scope could be expanded. As these three standards have been found acceptable to the majority of the current commenters, the SAR DT will now include them in the scope and will post the new SAR for approval.

Issue 1. The purpose of the SAR is to remove redundancies, the issue of SOLs is left to the Industry decide by the process. If this particular SAR does not meet ATC's concerns then ATC should submit its own request.

Question #1			
Commenter	Yes	No	Comment

Regarding the question of being prescriptive (which in the next paragraph ATC states we should further limit) - the SAR DT was prescriptive in exactly what is to be in the scope of work. The idea was to ensure that the Standards DT isn't inundated with other people's unrelated issues. ATC states that the scope is incomplete but does not specify how to complete it. Is it a redundancy that was missed or is it an unrelated issue? The SAR simply proposes a scope of work designed primarily to eliminate redundancies. Deletion or changes to existing requirements would occur in the standards drafting process.

We agree with ATC that the scope should be focused (i.e., prescriptive) on removing redundancies.

For items that are not included in this SAR's scope, ATC is encouraged to submit its own scope of work

Regarding **Issue 2a** – ATC lists a number of standards that are addressed in various other NERC projects. The SAR DT would remind ATC that each standard has more than one requirement. And it is these diverse requirements that each Project is addressing. If there is overlapping requirements then ATC is encouraged to bring that to the attention of NERC Staff.

Lastly, the SAR DT works at the will of NERC. The DT was assigned to begin its work and complete its scoping document. If ATC does not agree with NERC starting this project, then they should inform the NERC staff and the NERC Standards Committee of their concerns.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Hydro-Québec TransÉnergie		☑	Both IRO-006-3 and draft IRO-006-4 have the TOP listed in applicability section. However, neither actually has any requirement in the standard. They simply reference the TOP in the requirements. We think that the scope should not be restricted to only eliminate redundancy in IRO-004, -005 and -006 but should permit other changes in those standards. Hydro-Québec TransÉnergie would probably have some proposition to make because of the characteristics of Québec Interconnexion. The SAR drafting team should modify the scope so that all requirements to monitor and control flows within SOLs are not eliminated. While the SAR drafting team points out in their response to the comments that NERC's definition defines an SOL as local, eliminating all requirements to monitor and control to SOLs will be detrimental to reliability. Multiple SOLs occuring on a system may be a sign of an undetected IROL or, if left unchecked, propagate into an IROL. This was the cause of the August 14th blackout. Clearly there should be an obligation on the part of the TOP and RC to monitor and mitigate these limits to prevent such propagation.

HQ TransEnergie does not support expanding the scope.

Response:
The commenter is correct that the TOP is not in IRO-006.

When the Standards process begins, Hydro Quebec can suggest changes to those standards in scope. And if that is not suffcient Hydro Quebec is encougaged to submit its own SAR.

Regarding monitoring requirements, Hydro Quebec has a position on the requirements and they ask that the SAR DT protect that position. It is not the responsibility of the DT to protect a given position. This SAR is simply a scoping document.

IRO-005-2 R1 requires the RC to monitor SOLs. Clearly multiple SOLs in different parts of a system can only be coordinated by an RC. At best a TOP can only deal with its own limited subset. That is a current requirement and unless changed through the Reliability Standards Development Procedure, that requirement will remain.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on First Draft of Revised TOP Standards Real-time Operations — Project 2007-03

The Standards Committee thanks all commenters who submitted comments on the 1st draft of the revised TOP standards, Real-time Operations Project. These standards were posted for a 45-day public comment period from October 7, 2008 through November 20, 2008. The stakeholders were asked to provide feedback on the SAR through a special Standard Comment Form. There were more than 26 sets of comments, including comments from more than 90 different people from approximately 50 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

The SDT is recommending that the standards be re-posted to allow for feedback on the changes made due to industry comments to the first posting.

Changes have been made to the following:

- TOP-001-2 & TOP-003-1 Purpose statements
- Requirements:
  - TOP-001-2: R1, R2, R3, R4, and R7
  - TOP-002-3: R1, R2, and R3
  - TOP-003-1: R1, R4, and R5
  - TOP-004-3, R2
- Measures:
  - TOP-001-2, M1, M2, M3, M4, and M7
  - TOP-003-1, M1, and M4
  - TOP-004-3, M2
- Data retention:
  - TOP-001-2, R1 through R7
  - TOP-002-3, R3
  - Top-003-1, R1, R4, and R5
- VSLs:
  - TOP-001-2, R1, R3, R4, and R6
  - TOP-002-3, R1 and R3
  - TOP-003-1, R1, R2, R3, and R4
  - TOP-004-3, R1 and R2
- In addition, two bullets were added to TOP-003-1, Requirement R1.1 to address directives in FERC Order 693.

Definitions:

- Deleted the definition of “Simulated Contingencies” as stakeholders indicated the definition is not needed.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Guy Zito	NPCC										✓

	Additional Member	Additional Organization	Region	
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
3.	Mike Gildea	Constellation Energy		6
4.	Greg Campoli	New York Independent System Operator	NPCC	2
5.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
6.	Chris De Graffenried	Consolidated Edison Company of New York, Inc.	NPCC	1
7.	Don Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
8.	Brian Evans-Mongeon	Utility Services, LLC	NPCC	6
9.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Lee Pedowicz	NPCC	NPCC	10
12.	Kathleen Goodman	ISO - New England	NPCC	2

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
2.	Terry L. Blackwell	Santee Cooper	✓									

Commenter	Organization	Industry Segment									
		1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Glenn Stephens	Santee Cooper	SERC	1
3.	Jim Peterson	Santee Cooper	SERC	1
4.	Vicky Budreau	Santee Cooper	SERC	1
5.	Kristi Boland	Santee Cooper	SERC	1
6.	Rene' Free	Santee Cooper	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Jim Griffith	SERC OC Standards Review Group	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Brown	Big Rivers Electric Cooperative	SERC	1, 3, 5
2.	Robert Thomasson	Big Rivers Electric Cooperative	SERC	1, 3, 5
3.	Raleigh Nobles	Georgia System Operations Corp.	SERC	3
4.	Sam Holeman	Duke Energy Carolinas	SERC	1, 3, 5
5.	Greg Rowland	Duke Energy Carolinas	SERC	1, 3, 5
6.	Dan Jewell	Louisiana Generating, LLC	SERC	1, 3, 5
7.	Jason Marshall	MISO	SERC	2
8.	Larry Rodriquez	Entegra Power Group;	SERC	5
9.	Melinda Montgomery	Entergy	SERC	1, 3, 5
10.	Jim Case	Entergy	SERC	1, 3, 5
11.	John Troha	SERC	SERC	10

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Patrick Brown	PJM Interconnection		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al DiCaprio	PJM interconnection	RFC	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Louis Slade	Dominion - Electric Market Policy			✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jalal Babik		NA - Not Applicable	3, 5, 6
2.	Mike Garton		NA - Not Applicable	3, 5, 6

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Roman Carter	Southern Company Transmission	✓									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Wilson	Southern Transmission	SERC	1
2.	Terry Coggins	Southern Transmission	SERC	1
3.	JT Wood	Southern Transmission	SERC	1
4.	Jim Busbin	Southern Transmission	SERC	1
5.	Mike Oatts	Southern Transmission	SERC	1
6.	Jim Viikansalo	Southern Transmission	SERC	1
7.	Dushaune Carter	Southern Transmission	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Denise Koehn	Bonneville Power Administration	✓		✓			✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Snodgrass	Transmission Dispatch	WECC	1
2.	Jim Burns	Transmission Technical Operations	WECC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Jason Marshall	Midwest ISO Stakholders Standards Collaborators		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Cyrulewski	JDRJC Associates	RFC	8

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Dave Folk	FirstEnergy	✓		✓		✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FirstEnergy	RFC	1, 3, 5, 6
2.	Sam Ciccone	FirstEnergy	RFC	1, 3, 5, 6
3.	John Martinez	FirstEnergy	RFC	1
4.	Steve Megay	FirstEnergy	RFC	1

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
10.	Jim Haigh	MRO NERC Standards Review Subcommittee	✓					✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Charles Lawrence	ATC	MRO	1
5.	Ken Goldsmith	ALTW	MRO	4
6.	Terry Harbour	MEC	MRO	1, 3, 5, 6
7.	Pam Sordet	XCEL	MRO	1, 3, 5, 6
8.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
9.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
10.	Joseph Knight	GRE	MRO	1, 3, 5, 6
11.	Joe Depoorter	MGE	MRO	3, 4, 5, 6
12.	Larry Brusseau	MRO	MRO	10
13.	Michael Brytowski	MRO	MRO	10

			1	2	3	4	5	6	7	8	9	10
11.	Michael Ayotte	ITC Transmission	✓									
12.	Charles Yeung	IRC Standards Review Committee		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	NPCC	2
2.	Jim Castle	NYISO	NPCC	2
3.	Matt Goldberg	ISONE	NPCC	2
4.	Lourdes Estrada-Salinero	CAISO	WECC	2
5.	Anita Lee	AESO	WECC	2
6.	Steve Myers	ERCOT	ERCOT	2
7.	Bill Phillips	MISO	RFC	2
8.	Dan Rochester	IESO	NPCC	2

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
13.	Cleyton Tewksbury	Montenay Power Corp.					✓					
14.	John McCawley	PECO Energy	✓		✓							
15.	Craig McLean	Manitoba Hydro	✓		✓		✓	✓				
16.	Scott Berry	Indiana Municipal Power Agency				✓						
17.	Jianmei Chai	Consumers Energy Company			✓	✓	✓					
18.	Kirit Shah	Ameren	✓		✓		✓	✓				
19.	Darryl Curtis	Oncor Electric Delivery	✓									
20.	Will Franklin	Entergy System Planning & Operations (Gen & Mktg)						✓				
21.	Edward J Davis	Entergy Services	✓		✓		✓	✓				
22.	Dan Rochester	Independent Electricity System Operator		✓								
23.	Greg Rowland	Duke Energy	✓		✓		✓	✓				
24.	Thad Ness	AEP	✓		✓		✓	✓				
25.	Rick White	Northeast Utilities	✓									
26.	Jason Shaver	American Transmission Company	✓									

1. The SDT has deleted the phrase 'without intentional delay' from all situations that require specific actions or responses as it was felt that this term is unmeasurable and that operator action and response in a timely manner is part of good utility practice and common sense. Do you agree with this change? If not, please provide specific suggestions for improvement.

Summary Consideration:

The majority of respondents agreed with the deletion of the phrase 'without intentional delay' and thus no changes have been made to the standard.

Organization	Yes or No	Question 1 Comment
ISO-NE NPCC	No	Although we agree with the concept and agree that it is unmeasurable, we do not believe that removal of the concept is acceptable and suggest reqording to "as soon as possible but not more than..."
ISO-NE	Yes	We agree with the change. The drafting team could address the timeliness of actions in the VSLs. If directed by the FERC to maintain the language, we suggest the wording to be "as soon as possible but within the time limitation of the associated SOL".
Response: The use of the term "without intentional delay" was used in context with how quickly the responsible entity acts and not how quickly its actions achieved the desired response. Your suggestion appears to attempt to time bound the amount of time it takes to achieve results from the actions taken by the responsible entity. Thus, the SDT does not agree with your suggestion. Additionally, the definition of SOL does not include a time limit.		
IRC Standards ISO-NE NPCC Review Committee	Yes	We agree with the change. The drafting team could address the timeliness of actions in the VSLs. If directed by the FERC to maintain the language, we suggest the wording to be "as soon as possible but within the time limitation of the associated SOL".
Response: The SDT does not believe that timeliness should be addressed in the VSLs unless there is a clear measurable requirement for timeliness. The Commission established in their VSL order several guidelines, one of which requires that VSLs do not add to the requirement. Establishing timeliness in the VSLs when there is not a clear measurable requirement for timeliness would thus violate the Commission's guideline.		
Entergy Services	No	There is merit in holding entities accountable for making timely notifications, etc. Would an entity be compliant if they waited 6 months to notify the TOP of changed in Real Power capability? Perhaps the measures can be worded such that proof of the event's time and proof of the notification's time are not significantly different. However, we suspect that entities for which the requirement is applicable would WANT guidance on what is timely and what is not. Leaving that much up to the interpretation of audit teams is not very desirable.

Organization	Yes or No	Question 1 Comment
Response: While the SDT agrees with your point that entities would want guidance on what is timely and agree that the extreme example of six months would be far too long, the SDT noticed that you have not suggested a time requirement. Thus, the SDT concludes that you must have detected the problems with establishing a time requirement. Some of the problems include that what is timely in one situation and one applicable entity may ultimately vary with another. Thus, setting a specific time requirement that is measurable and usable in all situations is not appropriate. The SDT also agrees that it is not desirable to leave the interpretation of what is timely up to the compliance auditors but do not see a better way. Applicable entities will have to work with their TOP to assess what their expectations are as far as timeliness.		
Independent Electricity System Operator	No	This phrase should not be removed. If measurability is required, similar language ("without delay") in R4 of the recently approved IRO-009 standard should be used, with a condition to assess if there was a 5 minute delay for assigning a High VSL.
Response: This is the only comment that was received in this regard and the SDT (and the remainder of the industry as seen from comments received) continues to believe that removing the phrase is correct for TOP standards.		
Santee Cooper	Yes	
SERC OC Standards Review Group	Yes	This phrase is not measureable!
PJM InterconnectiC OC Standaon	Yes	PJM supports the deletion and recognizes the problem in measuring "intent".
Dominion - Electric Market Policy	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	
Midwest ISO Stakholders Standards Collaborators	Yes	Intent is an enforcement issue. Thus, it does not belong in the standard.

Organization	Yes or No	Question 1 Comment
FirstEnergy	Yes	
MRO NERC Standards Review Subcommittee	Yes	
ITC Transmission	Yes	
Montenay Power Corp.	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	
Oncor Electric Delivery	Yes	
Entergy System Planning & Operations (Gen & Mktg)	Yes	
Duke Energy	Yes	
AEP	Yes	
Northeast Utilities	Yes	
American Transmission Company	Yes	
Response: Thank you for your response.		

2. The SDT has eliminated SOLs from TOP-004-2, Requirement R1. The SDT felt that requiring a TOP to operate within all SOLs could effectively reduce the TOPs operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time. The SDT determined that operating within each IROL and its IROL T_v was the reliability issue in this requirement. Do you agree with deleting the language about SOLs in TOP-004-2, Requirement R1? If not, please provide specific suggestions for improvement.

Summary Consideration:

There was a general consensus amongst responders that the elimination was appropriate.

Organization	Yes or No	Question 2 Comment
SERC OC Standards Review Group	Yes	Although we agree with the SDT's change regarding SOLs, TOPs should not allow an unintended consequence of this change to be less emphasis on resolving or mitigating SOLs.
Response: The SDT agrees with you that the TOPs should not de-emphasize resolving or mitigating SOLs and do not believe the revised standard does this.		
Midwest ISO Stakholders Standards Collaborators	No	The TOP should be required to operate within SOLs. SOLs by definition can by be voltage or stability limited. SOLs, if exceeded, can be become IROLs. What in the standards will ensure that the TOP is sure the exceeding the SOL will not result in an IROL. The situation described in the question may not even require that an SOL be defined. No where in the standards is there a requirement that every thermal limit must be encompassed in a SOL. If a TOP decides to "ride" out an SOL rather than mitigate the violation, in reality the TOP has indicated that the current SOL is invalid. Why can't the TOP just determine what the new SOL is?
Response: IROLs must be determined by studies. To the extent that a TOP has an expectation that an SOL might be exceeded, the TOP and RC are obligated to verify that an IROL will not be exceeded. In other words, when determining the operating region, the TOP and RC must be aware of both the SOL operating region and the IROL operating region. Honoring every SOL could present problems to the TOP where they may have to choose to violate another requirement to meet the requirement to operate within all SOLs. For example, when two or more limits are in danger of violation, and mitigating one would exacerbate the other, the TOP clearly is faced with a reliability and compliance conundrum. Under the SDT's proposal, however, the TOP has the opportunity to monitor the status of the systems and make the wisest possible choice to preserve reliability. The SDT feels that the FAC standards address thermal limits.		
Independent Electricity System Operator	No	We strongly disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time."

Organization	Yes or No	Question 2 Comment
		SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability? Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? We are also very concerned that R1/R2 in TOP-002 requires the TOP to assess potential exceedence of IROLs only but not SOLs. This sends a the wrong message to the industry that TOPs do not need to plan their operations to within established SOLs. So why do we mandate the TOPs to calculate SOLs to begin with? We feel strongly that R2 in TOP-002 should be revised so that it includes as part of the requirement, preclusion of operating in excess of any SOLs. We believe that completely removing SOLs from the requirement is contrary to the long-term objective of enhancing reliability. Further, we believe that all SOLs should be respected in the planning time-frame and in real time with the exception of low likelihood or rare circumstances. We do recognize that there are instances where post-contingency, a TOP may not be able to respect its repreparation limits for the next contingency. Those instances must however be limited to situations in which, after applying available means to eliminate the violation short of firm load shedding, and where it can be demonstrated that the SOL violation cannot propagate into an IROL violation following the next worst contingency. That is, the repreparation limit is non-impactive to the BES. We need only recall that some blackout events started by exceedence of local area limits (SOLs). When sufficient events occur (such as when a line rating is not observed or its overload not corrected), cascade overloading on another transmission line and yet another transmission line and so on may occur. An apparently non-impactive SOL, if not observed and whose exceedence not corrected, can result in cascading outages.
Response: Your initial argument that exceeding an SOL may be the point where “system voltage may be depressed” focus on the subset of SOLs that are IROLs. There is an explicit requirement still in the proposed standards to operate within IROLs. Thus, the only SOLs that these proposed draft standards do require a TOP to operate within are those that exclude the IROL subset. The SDT does not believe that the proposed TOP standards conflict with the FAC-014 standard. Determining SOLs is required to operate the System and SOLs will be operated within in most instances. However, SOLs do not represent limits that if exceeded could cause cascading, uncontrolled outages or blackouts. Furthermore, part of the purpose of FAC-014 is to communicate your SOLs to other entities so that they can respect your operational limits.		
IRC Standards Review Committee	Yes	SOLs should be mitigated within their equipment time limits. Though we are not prepared to propose a specific time period due to the limited time to provide comments on such a complex issue, we ask that the SDT work with industry to develop an appropriate time period that is measurable and propose it for consideration. The procedures should

Organization	Yes or No	Question 2 Comment
		give appropriate consideration to consequences that are more severe than the violation.
Response: SOLs may be based on equipment time limits but by definition there is not an associated T_v and any decision to associate a time limit with the SOL to protect the equipment from damage is an independent operational decision that is made by the TOP and TO. Thus, the SDT does not believe it is necessary to establish a time limit.		
AEP	Yes	The purpose statement in TOP-004-1 is consistent with the IROL NERC defined term. We suggest keeping the original purpose statement from TOP-004-1. If SOL are to be reported then some prioritization needs to be given. We suggest reporting the largest SOL if there are several common to an area of congestion.
Response: Purpose statement **–** No other comments were received and the SDT feels that the changes properly reflect what was changed in the standard so no changes made**.** Prioritization or largest SOL – Most commenters support the removal of SOLs. Therefore, no change is required.		
ISO-NE	Yes	SOLs should be mitigated within a defined time period with appropriate consideration to the consequences
NPCC	Yes	
Santee Cooper	Yes	
PJM Interconnection	Yes	The SDT has correctly balanced the need for flexible responses to non-impactive problems.
Dominion - Electric Market Policy	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Subcommittee	Yes	
ITC Transmission	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	This change is consistent with the fact that BES operation is a risk-based endeavor. While IROL risk is so severe it is unlikely to be properly evaluated by a TOP, SOLs should be considered as part of the normal risk assessment.
Oncor Electric Delivery	Yes	
Entergy Services	Yes	We agree as this was the original intention of the NERC OLDTF that first developed the terms SOL and IROL.
Duke Energy	Yes	We agree with the SDT's logic in eliminating SOLs from TOP-004-2 Requirement R1.
Northeast Utilities	Yes	
American Transmission Company	Yes	
Response: Thank you for your response.		

3. The SDT is concerned about the inclusion of SOL in TOP-001-2, Requirement R5. The SDT thinks that the TOP notifying its RC of every SOL that has been exceeded may create an overload of messages for the RC that does not facilitate preserving reliability. Do you agree that SOL should remain in this requirement? If not, please provide specific suggestions for improvement.

Summary Consideration:

This question was poorly worded and as a result the commenters may have been led astray. The consensus of the industry at this point is that not all SOLs need to be reported but that some subset of them should. The SDT will re-phrase the question in the second posting so that the intent is clear and so that a definitive position on the issue can be established.

Organization	Yes or No	Question 3 Comment
NPCC	No	We agree that not every SOL requires communications to another entity. However, there are subsets of SOLs that have the potential to become IROLs or, outside of that subset, left unmitigated, there are other SOLs which will become IROLs. We believe that there should be a requirement to inform the RC when these conditions occur.
ISO-NE	No	We agree that not every SOL requires communications to another entity. However, there are subsets of SOLs that have the potential to become IROLs or, outside of that subset, left unmitigated, there are other SOLs which will become IROLs. We believe that there should be a requirement to inform the RC when these conditions occur.
Santee Cooper	No	Notification should be provided to the RC only when an IROL is exceeded. Too much information flowing to the RC could potentially mask a reliability problem.
SERC OC Standards Review Group	Yes	We interpret this requirement to indicate that a TOP is required to inform the RC only if action is taken to mitigate an SOL, i.e., if the TOP decides that no action is required for an SOL, the TOP is not required to notify the RC.
Manitoba Hydro	No	As per TOP-004-3, exceeding an SOL does not necessarily put the BES at risk. The SOL for a thermal limit could very well be set for an ambient temperature much higher than the actual ambient temperature. Notifying the RC for such an event would be a waste of resources. We feel it is not necessary to make it mandatory to notify the RC when exceeding a SOL. TOPs should be mandated by a Requirement to document all SOL violations and action taken. Such action may include but is not limited to: simply further monitoring or making a temporary alarm level adjustment.
PJM Interconnection	No	The issue here is in defining what is impactive and what is not. A flow value that creates a temporary overload on a radial line may not be of concern to an RC, thus informing the RC that the flows are under the limit is merely a distraction. During Emergency Conditions such non-relevant information can be more then distractive it can needlessly tie up people

Organization	Yes or No	Question 3 Comment
		to the point of causing those people to overlook real problems. The standard could be written to include a requirement that the RC must inform the TOP of any overloads that it, the RC, requires to be informed of. Then the TOP is obligated to provide information about the critical SOLs and mandated to report on the relief of every SOL.
Dominion - Electric Market Policy	Yes	Suggest revising R5 to read "Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when a reportable SOL (as identified by its Reliability Coordinator)has been exceeded. Suggest revising R6 to read "The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv and shall inform its Reliability Coordinator of such actions.
Southern Company Transmission	No	Requirement 2 of TOP-001-2 already contains a provision for the TOP to inform its RC of real-time or anticipated emergency conditions. If a particular SOL is considered an emergency condition, then it would be reported. Otherwise, it is not required. Therefore, we agree that notifying the RC of every SOL is not necessary.
Ameren	No	This has proven to be a duplicative effort since the RC is monitoring the facilities also. Change the text to say, "to the extent that the RC does not have systems in place, the TOP will ?.".
Midwest ISO Stakholders Standards Collaborators	Yes	We believe that the TOP notifying the RC of every SOL that has been violated does not create an overload messages. The TOPs in the Midwest ISO reliability footprint already notify the RC of all SOL violations and we have not found it to be a burden. In fact, we have found it actually improves operations because it causes the RC to continuously validate the results of the real-time contingency analysis against the TOPs. We do believe that the requirement should not be prescriptive to require a particular type of communication such as via the phone. To a certain degree this requirement can be met by simply having redundant models and contingency analysis in the EMS. We observe that the requirement is not for the TOP to notify the RC every time that an SOL is violated. In fact, the requirement is only to notify the RC of the actions to be taken. Thus, if no actions are taken, the TOP does not have to notify the RC. We believe the language should be strengthened to clarify that the TOP should notify the RC every time an SOL is violated even when no mitigation is taken.
FirstEnergy	No	However, the SDT should develop rules that will drive the reporting of incidences where entities exceed SOLs on a regular basis. As an example: the operating studies show that the facility emergency thermal limit is expected to be exceeded by 25% for 4 consecutive hours of 5 consecutive operating days. The goal should be to flag instances where SOLs are exceeded on a regular or routine basis in an effort to highlight situations where mitigation actions or system reinforcement projects may be needed or required to preserve the reliability of the BES.
ITC Transmission	No	Presumably the RC should be aware when an SOL has been exceeded by their own EMS and contingency analysis program.

Organization	Yes or No	Question 3 Comment
Montenay Power Corp.	No	
Ameren	No	This has proven to be a duplicative effort since the RC is monitoring the facilities also. Change the text to say, "to the extent that the RC does not have systems in place, the TOP will ?.".
Entergy System Planning & Operations (Gen & Mktg)	No	The RC should be aware of SOL exceedances in order to perform their function and maintain situational awareness.
Entergy Services	No	SOLs should be removed. While certain SOLs may need to be communicated to the RC per internal processes, only IROLs should be required to be reported. Reporting of every SOL could "water down" the communications to the RC and add confusion when IROLs are reported.
Independent Electricity System Operator	Yes	SOLs are intended to ensure reliable operation of the BES. TOPs, who calculate these SOLs to begin with, shall not intentionally operate its system to be very near or exceeding SOLs. Thus, we do not expect SOL exceedences to occur so frequently that reporting to the RC will create an overload of messages.
Northeast Utilities	No	We do not believe that the TOP informing the RC of every SOL exceedance should be required, and would not facilitate preserving reliability. Suggest removing "or SOL" from the requirement.
Duke Energy	Yes	R5 should be revised to also require the TOP to notify the RC of the particular IROL or SOL that has been exceeded.
AEP	Yes	The TOP-001-1 purpose statement deals with emergencies and taking actions to resolve them. The TOP-001-2 purpose statement deals with coordination. We concur that notifying the RC of every SOL violation could be overwhelming and counter productive to reliability. If SOL are to be reported then some prioritization needs to be given. We suggest reporting the largest SOL if there are several common to an area of congestion.
Response: This question was poorly worded and as a result the commenters may have been led astray. The consensus of the industry at this point is that not all SOLs need to be reported but that some subset of them should. The SDT will re-phrase the question in the second posting so that the intent is clear and so that a definitive position on the issue can be established.		
Bonneville Power Administration	No	Agree that it would increase workload while trying to return the system within limits. This requirement should probably move to TOP-004-3. R6 should maybe move there also as Real-Time Operations?

Organization	Yes or No	Question 3 Comment
Response: The SDT believes that it could be moved and be equally effective however this is the only comment received on this matter so the SDT is not going to make a change.		
American Transmission Company	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your response.		

4. TOP-002-3 Requirement R1 uses the new proposed term Simulated Contingency. The term's use is intended to clarify that the Contingencies used in the next day assessment are intended to model Contingencies that could occur based on the projected System topology and not Contingencies that have actually occurred on the System. The SDT is concerned that the definition may inadvertently lead the reader to believe that a power System simulator is required. Do you believe that the definition and term accomplish the intention of clarifying TOP-002-3 Requirement R1 without confusing the reader into believing a power System simulator is required? If not, please suggest alternative wording for TOP-002-3 Requirement R1 that communicates the SDT's intent.

Summary Consideration:

After review of all comments received, the SDT believes that the addition of the definition is not necessary. Accordingly, the definition will be eliminated and the wording of TOP-002-3, Requirement R1 has been revised accordingly.

TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Organization	Yes or No	Question 4 Comment
NPCC	No	Change the definition of Simulated Contingencies to: "The act of using planning and operating models to replicate Contingency responses."
Santee Cooper	No	Don't believe the current definition implies that a simulator is required. However, the definition of Simulated Contingency is not clear and very ambiguous. Suggested definition for Simulated Contingency is a contingency evaluated using planning and operating models of the BES.
Oncor Electric Delivery	No	"Study Contingency" may be a better choice and would remove the possible link between simulator and simulated contingency
American Transmission Company	No	The phrase "Simulated Contingency" should be replaced with a more concrete concept. ATC suggest that the SDT link the requirement to FAC-011. The purpose of FAC-011 is to ensure that SOLs used in the reliability operations of the BES are determined based on an established SOL methodology.
Response: The definition was intended to indicate that, although studies are not required for an assessment, the assessment should include all expected results from the System response to Contingencies which had been modeled in the development of System Operating Limits. The methodology of developing the SOLs includes the Contingencies that are to be considered in the development of those limits. The SDT has revised the wording of Requirement R1 to simplify and clarify		

Organization	Yes or No	Question 4 Comment
expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
SERC OC Standards Review Group	No	For additional clarification, we suggest the following alternative wording for the Definition of Simulated Contingencies: "The act of using planning and operating models to model single branch or unit outages in the modeled network."
Duke Energy	No	We believe that the definition of Simulated Contingencies should be revised as follows: The act of using planning and operating models to model single branch or unit outages in the modeled network.
Response: The SDT feels that the information you suggest is addressed in the required methodology to be used in the development of System Operating Limits**.** The definition was intended to indicate that, although studies are not required for an assessment, the assessment should include all expected results from the System response to Contingencies which had been modeled in the development of System Operating Limits. The methodology of developing the SOLs includes the Contingencies that are to be considered in the development of those limits. The SDT has revised the wording of Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
PJM Interconnection	No	The definition needs more work to avoid confusion. The word "simulated" will itself likely be a point of contention. One solution would be to delete the word "simulated". If this issue of post-contingency simulation becomes a problem, then a Standard Interpretation can be issued.
Southern Company Transmission	No	The proposed definition of "Simulated Contingency" is not clear. Also, it is not apparent why a new definition is even needed. Make the definition part of the requirement. Why couldn't ?Simulated? be replaced with something like "depicted", "represented" or "portrayed". Possible wording for the Requirement 1 might be ?The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOL's) during anticipated normal conditions and Contingency events represented through planning and operational analysis models reflecting design parameters and system conditions.? In the event the drafting team does not agree to implement our suggested change above, the drafting needs to address this issue also in IRO-004-01, R1 where the requirement states normal or anticipated contingency events and not "simulated events". The two requirements should be consistent in terms.
Bonneville Power Administration	No	Change the definition from "design considerations" to "planned outages".
Response: After reviewing all comments submitted, the SDT agrees that the definition seems to lack needed clarity The definition was intended to indicate that,		

Organization	Yes or No	Question 4 Comment
although studies are not required for an assessment, the assessment should include all expected results from the System response to Contingencies which had been modeled in the development of System Operating Limits. The methodology of developing the SOLs includes the Contingencies that are to be considered in the development of those limits. The SDT has revised the wording of Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
Dominion - Electric Market Policy	No	We suggest revising the stated purpose rather than creating a new definition. We suggest revising purpose to read " To ensure that reliability entities have coordinated plans for meeting expected operating conditions including contingencies that could occur based on projected system topology."
Response: The SDT believes that the existing purpose statement is appropriate and that required methodologies for determination of system operating limits include the concept of contingencies that could occur and the projected system topology**.** After reviewing all comments submitted, the SDT agrees that the definition seems to lack needed clarity The definition was intended to indicate that, although studies are not required for an assessment, the assessment should include all expected results from the System response to Contingencies which had been modeled in the development of System Operating Limits. The methodology of developing the SOLs includes the Contingencies that are to be considered in the development of those limits. The SDT has revised the wording of Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
Midwest ISO Stakholders Standards Collaborators	No	Why can't you just use the term potential in front of Contingency?
ITC Transmission	No	Suggest using the phrase "potential contingency" rather than "simulated contingency".
ISO-NE	No	We suggest using the term "potential contingencies" and avoid coming up with a new definition. The proposed definition is unclear and will lead to confusion.
IRC Standards Review Committee	No	We suggest using the term "potential contingencies" and avoid coming up with a new definition. The proposed definition is unclear and will lead to confusion.
AEP	No	The "Simulated Contingency" definition lacks clarity and its use in TOP-002-3 R1 does imply that an offline load flow program would be required when conducting a next day assessment. Suggested wording: Replace "and Simulated Contingency" with "and/or potential contingency".

Organization	Yes or No	Question 4 Comment
Response: After reviewing all comments submitted, the SDT agrees that the definition does not lend added clarity. Your suggestion is a good one. The SDT has revised the wording of TOP-002-3, Requirement R1. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
FirstEnergy	No	We believe that the definition is not needed and that the use of the word "simulated" in and of itself provides sufficient clarity that the requirement does not refer to actual Contingency events. The premise of the requirement is an assessment of "next day" system condition so it is unclear how this could in anyway be construed to be an actual contingency event. However, what is not clear in the requirements is what type of contingencies are to be evaluated? Is it single Contingency (N-1) events only. What if bus faults were not studied would there be a potential for non-compliance? There should be some tie to the TPL standards to specifically identify which Contingencies must be evaluated for Next Day analysis.
Ameren	No	This change is not necessary. The "Contingency" definition is for things that could but are not certain to happen. Obviously, there is no basis for a contingency that has occurred. Once occurred, it is an event.
Response: After reviewing all comments submitted, the SDT agrees that the definition is not needed. The SDT has revised the wording of TOP-002-3, Requirement R1. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* As to what type of Contingency must be considered, the Transmission Operator is not limited to single Contingencies or bus faults but must study any and all conditions that may result in exceeding any of its System Operating Limits during anticipated normal conditions as stated in the Requirement. The potential Contingencies to be studied are limited to those spelled out in the TPL standard.		
Entergy Services	No	There can be much confusion with the standards when terms are used in multiple ways. The poster child for this is "critical facilities." I agree with the intent of the SDT, but suggest the term "Postulated Contingencies."
Independent Electricity System Operator	No	We do not see the need to define this new term. Further, the definition is inaccurate (mixing contingency which is a "what-if" event with system response) and confusing (we are unable to understanding the meaning of "the net effect of design considerations" in an operational planning assessment domain. Having said that, we do not interpret the term to mean the requirement for a "simulator". To eliminate the concern of misinterpretation, we suggest that R1 be reworded to "? during anticipated normal conditions and analyzed contingency events."
Response: After reviewing all comments submitted, the SDT believes that use of the term "potential Contingencies" is appropriate. The SDT will revise the wording		

Organization	Yes or No	Question 4 Comment
of TOP-002-3, Requirement R1 to simplify and clarify. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*.		
Northeast Utilities	No	Suggest adding the words "such as P/SSE, power flow, etc." to the definition after the word "models". This might help to clarify the intent. Ending the definition after the word "responses" would make it a cleaner definition. Additionally, the defined term is "Simulated Contingencies". R1 uses the term "Simulated Contingency". This should be reconciled by either changing the defined term, or R1 should use the defined term and drop the word "events" from the end of the sentence.
Response: After reviewing all comments received, the SDT believes the definition does not lend needed clarity. Further, the SDT recognizes that an assessment does not necessarily require a study to be performed each time the assessment is made. The SDT agrees that a robust underlying power flow study or model effort may be a good basis for an assessment, but is not required in all cases. After reviewing all comments submitted, the SDT believes that use of the term "potential Contingencies" is appropriate. The SDT has revised the wording of TOP-002-3, Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
MRO NERC Standards Review Subcommittee	Yes	
Consumers Energy Company	Yes	
Entergy System Planning & Operations (Gen & Mktg)	Yes	The definition of "Simulated Contingency" provides enough clarity to avoid confusion.
Response: Thank you for your response. Note that most commenters indicated that the definition wasn't needed or was unclear. After reviewing all comments submitted, the SDT believes that use of the term "potential Contingencies" is appropriate. The SDT has revised the wording of TOP-002-3, Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		

5. TOP-004-2, Measure M1: The SDT has adopted the position for this measure and others like it that the absence of an IROL Violation Report is a sufficient measure as opposed to retaining massive amounts of data for later audit. Do you agree with this assessment? If not, please provide specific suggestions for improvement.

Summary Consideration:

The consensus of comments received from industry is in agreement with the SDT position so no changes were made.

Organization	Yes or No	Question 5 Comment
MRO NERC Standards Review Subcommittee	No	This question is not consistent with TOP-004-2 M1, you either need the report or the data. You should be able to prove compliance with the report, stating absence of an IROL Violation Report in the question does not make sense.
Independent Electricity System Operator	No	First of all, we do not agree with the removal of SOL from R1 so we do not agree with M1.On the approach the SDT is proposing, we do not agree with the rationale that the absence of an IROL violation report is a sufficient measure. We believe the TOP should be required to provide evidence to demonstrate compliance (in this case, the data showing operating within IROL and Tv).
Response: If there has been no IROL violation, then there will be no violation data. The SDT believes that requiring retention of massive amounts of normal operating data does not make sense. The SDT believes that IROL Violation Reports, and the required supporting information, serves the purpose. Absence of the report indicates there has been no violation.		
Bonneville Power Administration	Yes	SDT has cleaned up TOP-004-3 well, removing duplicate requirements from other standards. I don't believe R2 (Agreements of switching) is necessary since TOP-001-2 R3 appears to cover assisting to mitigate emergencies/IROLs. It seems to me TOP-001 R5 and R6 are also real time operations and should go to TOP-004-3 has R2 and R3.
Response: The SDT believes that you have raised a legitimate point on TOP-004-3, R2 and will raise a question in the next posting to see what the industry feels on this topic. The SDT believes that it could be moved and be equally effective however this is the only comment received on this matter so the SDT is not going to make a change		
ISO-NE	Yes	We agree that having evidence of proof for non-events does not make sense. These are event-triggered standards and the focus should be to have evidence of compliance when an event in which compliance was required occurred. Some

Organization	Yes or No	Question 5 Comment
		would argue that evidence is needed because a TOP could fail to report an event. It should be kept in mind that a TOP that fails to report a violation would also be able to manipulate data to show continuous compliance.
IRC Standards Review Committee	Yes	We agree that having evidence of proof for non-events does not make sense. These are event-triggered standards and the focus should be to have evidence of compliance when an event in which compliance was required occurred. Some would argue that evidence is needed because a TOP could fail to report an event. It should be kept in mind that a TOP that fails to report a violation would also be able to manipulate data to show continuous compliance.
NPCC	Yes	We agree that having evidence of proof for non-events has no value. The focus should be to have evidence of compliance for instances when an event in which compliance was required occurred.
Santee Cooper	Yes	
SERC OC Standards Review Group	Yes	
PJM Interconnection	Yes	
Dominion - Electric Market Policy	Yes	
Southern Company Transmission	Yes	
Midwest ISO Stakholders Standards Collaborators	Yes	
FirstEnergy	Yes	
ITC Transmission	Yes	
Manitoba Hydro	Yes	
Consumers Energy	Yes	

Organization	Yes or No	Question 5 Comment
Company		
Ameren	Yes	An absence is sufficient.
Oncor Electric Delivery	Yes	
Entergy System Planning & Operations (Gen & Mktg)	Yes	
Entergy Services	Yes	
Duke Energy	Yes	
Northeast Utilities	Yes	We agree that having evidence of non-events has little value.
American Transmission Company	Yes	
Response: Thank you for your response.		

6. The SDT has included VRFs and Time Horizons with this posting. Do you agree with the assignments that have been made? If not, please make specific suggestions for improvement.

Summary Consideration:

While the SDT appreciates the perspective of comments for increasing the proposed Violation Risk Factors for various Requirements, the position taken by the SDT was to recognize that these standards represent not best practices, but the threshold of performance below which warrants penalties; including the potential for very severe penalties. The SDT, therefore, drafted and continues to support the position that only non-performance which, in itself, creates an adverse impact on reliability warrants a high VRF. Further, specific non-performance which may exacerbate (but not cause) an adverse impact on reliability generally may not warrant a high VRF because absent the non-performance in the primary area of concern, an adverse impact to reliability would not exist or would be minimal.

In each case, the SDT adopted the most appropriate level of risk assignment. This was done considering the following:

1. Direct correlation of adverse impact to reliability through non-performance of the specific requirement,
2. Whether non-performance of the specific requirement represented less-than-best practice as opposed to or compared with inadequate performance that represents dereliction of duty or imposing burden on others and which warrants penalty (i.e., performance which is merely less than best practice, but still adequate for reliability should not create or exacerbate risk)
3. The timing or urgency for which the adverse impact to reliability could occur

The following changes were made due to industry comments:

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions

TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

TOP-002-3, R2: The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

TOP-002-3, R3: The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

TOP-003-1, R5: Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>NPCC</td><td>No</td><td>TOP-001 - all VRFs but R4 should be HIGH (change R5 and R7).

TOP-002 - raise R1 from Low to Medium. It is more than just an administrative requirement.</td></tr>
<tr><td>PJM Interconnection</td><td>No</td><td>TOP-001 - all VRFs but R4 should be HIGH (change R5 and R7)

TOP-002 - raise R1 from Low to Medium some type of OPB assessment is required, it is more then just an administrative requirement.</td></tr>
<tr><td colspan="3">Response: TOP-001: With no reasons provided for the suggested changes, the SDT doesn't have any basis for making these changes.

TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. The presumption was that while the TOP is required to meet R1 and, therefore, need not have additional requirements to tell HOW Requirement R1 is met. However, comments prompted further consideration. It is apparent that adjacent entities would not be able to meet Requirement R1 without information otherwise unknown to them. That lack of information in the Operations Planning timeframe could cause that planning to be flawed. Therefore, the SDT is increasing this VRF from low to medium.

TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]</td></tr>
<tr><td>SERC OC Standards Review Group</td><td>No</td><td>For TOP-001, R1, R2, R4 - the risk factor should not be the same for each time horizon shown. i.e., for operations planning, same day operations, real-time operations.

We suggest R5 should have a Low VRF.

For TOP-002-3, the time horizon for each of these requirements (R1-R3) should be "Operations Planning".</td></tr>
<tr><td colspan="3">Response: The SDT did not see a need for a different VRF for each Time Horizon.

R5 - The SDT disagrees. It is important to advise the Reliability Coordinator of actions being taken to restore limits, etc. Absent such reporting and coordination, the chances increase that the RC may direct others to take actions which are either duplicative or counter to the actions being taken by the TOP to restore operations to within limits. Minimally, informing the RC of actions would enable the RC to assure that the event does not escalate. The risk created by not informing the RC of actions being taken warrants higher than a low VRF.

TOP-002-3: The SDT agrees. The Time Horizons for Requirements R1 – R3 have been changed to Operations Planning.

TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

TOP-002-3, R2: The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. [Violation Risk Factor: High] [Time Horizon: Operations Planning]</td></tr>
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<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">TOP-002-3, R3: The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). [Violation Risk Factor: High] [Time Horizon: Operations Planning]</td></tr>
<tr><td>Dominion - Electric Market Policy</td><td>No</td><td>TOP-001-2We believe that R5 and R7 warrant high VRF.
TOP-002-3 R1 warrants something higher than low. How can the TOP meet the intent of R2 (VRF = high) if it has failed at R1? We suggest that R1 and R2 should be high.
R3 should be reduced to low since the RC is required by IRO-004-1 @R3 to develop action plans in conjunction with its TOPs. The heavier burden should be placed on the RC.
The time horizon for R1-3 should be changed to Operations Planning</td></tr>
<tr><td colspan="3">Response: TOP-001-2: With no reasons provided for the suggested changes, the SDT doesn't have any basis for making these changes
TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. However, comments prompted further consideration. It is apparent that adjacent entities would not be able to meet Requirement R1 without information otherwise unknown to them. That lack of information in the Operations Planning timeframe could cause that planning to be flawed. Therefore, the SDT is increasing this VRF from low to medium.
TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]
TOP-002-3, R3: The SDT disagrees. While the burden for "bigger picture" (i.e., the heavier burden) may rest on the RC, communications are required from the TOP for any expected performance or awareness by any other entity included in the plan (includes RC). If conflicting performance expectations occur, or there is a need to revise plans based on the RC review of all respective TOPs plans, then these should be resolved by the RC, as noted in the cited IRO standard. But absent the sharing of this information, it s not clear how others (including the RC) would be made aware of plans (which can then be coordinated among TOPs by the RC as needed).
TOP-002-3: The SDT agrees. The Time Horizons for Requirements R1 – R3 have been changed to Operations Planning.
TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]
TOP-002-3, R2: The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
TOP-002-3, R3: The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). [Violation Risk Factor: High] [Time Horizon: Operations Planning]</td></tr>
<tr><td>FirstEnergy</td><td>No</td><td>The VRF for TOP-001-2 R7 should be a "High." Failure to follow the most conservative limit in times of uncertainty could negatively impact real-time reliability.</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>The VRF for TOP-002-1 R4 seems inconsistent. It has a qualifying concept of urgency of time in the phrase "? unless System conditions do not permit such coordination." which implies critical to the reliability of the BES yet it has been assigned a Medium VRF. Also, failure to coordinate an action may not always result in an impact on the BES, but the action does in theory bear a risk to the reliability of the BES. This VRF should be a High.

The VRFs for TOP-002-3 seem inconsistent. Requirement 2 which requires planning to mitigate a potential IROL discovered in the study required under R1 has a High VRF while R1 which requires the study be done has a Low. It is difficult to understand how a source requirement such as R1 can have a lower VRF then a derivative requirement such as R2. R1 and R2 should both have Medium VRFs since they are planning in nature and do not have an immediate impact on the BES.

The VRF for TOP-003-1 R4 and R5 seem inconsistent. The drafting team appears to consider it a Medium risk for an entity not to supply operating data to its Transmission Operator, but a Low risk for that Transmission Operator not to supply the operating data to an entity "with immediate responsibility for operational reliability." The VRF for R5 should also be a Medium.</td></tr>
<tr><td colspan="3">Response: TOP-001-2, R7: The SDT has deleted Requirement R7 as duplicative of IRO-05-3, Requirement R10.

TOP-002-3, R4: There is no Requirement R4.

TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. However, comments prompted further consideration. It is apparent that adjacent entities would not be able to meet Requirement R1 without information otherwise unknown to them. That lack of information in the Operations Planning timeframe could cause that planning to be flawed. Therefore, the SDT is increasing this VRF from low to medium.

TOP-002-3, R2: The SDT disagrees. Since IROLs are involved, the SDT feels that by definition the VRF must be high.

TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day’s operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

TOP-003-1, R4 & R5: The SDT agrees. The VRF for Requirement R5 has been changed to Medium.

TOP-003-1, R5: Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]</td></tr>
<tr><td>ISO-NE</td><td>No</td><td>TOP-001R1: A High VRF may not be appropriate in all cases. There are some directives that relate to local limits that would by no means result in cascading outages or instability. Perhaps the VSL matrix should assign a low VSL for non IROL directives.

R2: We are unable to assess the VRF for this requirement since we do not understand the meaning of "?.potential impacts</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
		caused by disconnections prior to switching." R3: We do not necessarily agree with a High VRF for the same reason as for R1, unless the VSL matrix addresses the difference between extreme events and local issues. TOP-002R1: We suggest raising the VRF for R1 to a Medium. TOP-003R5: Should perhaps be elevated to Medium if the measure were more specific. An entity can't prove the negative (prove you've provided data to every entity that requested it). The measure and VSL should deal with a complaint being submitted by an operating entity that did not get the data it needed and requested.
IRC Standards Review Committee	No	TOP-001R1: A High VRF may not be appropriate in all cases. There are some directives that relate to local limits that would by no means result in cascading outages or instability. Perhaps the VSL matrix should assign a low VSL for non IROL directives. R2: We are unable to assess the VRF for this requirement since we do not understand the meaning of "?.potential impacts caused by disconnections prior to switching." R3: We do not necessarily agree with a High VRF for the same reason as for R1, unless the VSL matrix addresses the difference between extreme events and local issues. TOP-002R1: We suggest raising the VRF for R1 to a Medium. TOP-003R5: Should perhaps be elevated to Medium if the measure were more specific. An entity can't prove the negative (prove you've provided data to every entity that requested it). The measure and VSL should deal with a complaint being submitted by an operating entity that did not get the data it needed and requested.
Independent Electricity System Operator	No	TOP-001R1: We do not agree with a High VRF. Not complying with the TOP's directives does not necessarily result in cascading outages or instability. And since the responsible entities are allowed to not comply with the directives for safety and other reasons, we are unable to rationalize how impactive a risk can be when an entity violates this requirement. R2: We are unable to assess the VRF for this requirement since we do not understand the meaning of "?.potential impacts caused by disconnections prior to switching." R3: We do not agree with a High VRF for the same reason as for R1, viz. if provisions for not complying is given, how high a risk it is if a responsible entity violates this requirement? TOP-002R1: We suggest raising the VRF for R1 to a Medium. Day ahead operational assessment of system conditions against established limits is essential in ensuring sufficient resources are available and operational plans are in place to prevent exceeding limits and to provide mitigating measures when such exceedence occurs. This assessment uses established limits and as such, is equally impactive, if not more impactive, than developing the limits themselves.

Organization	Yes or No	Question 6 Comment
		TOP-003R5: We do not agree with a Low VRF assigned to this requirement whose intent is essentially the same as R4 except R5 goes beyond the local TOPs and BAs to the adjacent or higher level entities, which also need this data to ensure reliable operation. We suggest this VRF should be Medium - the same for R4.
Response: TOP-001-2, R1**:** The SDT disagrees. Directives should be followed. What is described here by the commenter is a need to provide better directives… but if a directive is given it must be presumed in Real-time to be needed, and must be followed. As appropriate after the fact, a review of the directive can be made with a goal toward higher quality directives. But in Real-time the SDT position is that if directives are not followed, a high risk to reliability is likely. Therefore, the SDT disagrees with the comment and no change has been made. TOP-001-2, R2: The intent of the phrase was to note one of the areas especially necessary to communicate (i.e., the opening of Interconnections or connections to generators, areas, etc). This is one of many things that need to be communicated if System conditions permit. Since this specific phrase was confusing to some, and since it describes only one of many possible conditions, the SDT has deleted the phrase. **TOP-001-2, R2:** Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions. TOP-001-2, R3: The SDT disagrees and has left the VRF as is. If emergency assistance is requested it should be rendered if available. If it is requested for improper reasons or is found to be a convenience rather than a necessity, then such a finding should be dealt with after the fact. But during the emergency period, requests should be honored (if possible without threatening life or property, or violating laws or other regulations, standards, etc.). TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* TOP-003-1, R5: The SDT agrees. The VRF for Requirement R5 has been changed to Medium. **TOP-003-1, R5**: Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*		
Entergy Services	No	TOP-002-3 R1: VRF should be Medium since you can't do R2 or R3 without it. TOP-003-1 R5 - VRF should be Medium, the same as R4
Response: TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* TOP-003-1, R5: The SDT agrees. The VRF for Requirement R5 has been changed to Medium.		

Organization	Yes or No	Question 6 Comment
TOP-003-1, R5: Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*		
Northeast Utilities	No	TOP-002 - Raise R1 from Low to Medium.
Response: TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
American Transmission Company	Yes	
Santee Cooper	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Subcommittee	Yes	
ITC Transmission	Yes	
Montenay Power Corp.	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	

Organization	Yes or No	Question 6 Comment
Oncor Electric Delivery	Yes	
Duke Energy	Yes	
Response: Thank you for your response.		

7. The SDT has included Measures and Data Retention with this posting. Do you agree with the assignments that have been made? If not, please make specific suggestions for improvement.

Summary Consideration:

While the majority of the commenters agreed with the parameters, the following changes have been made due to industry comments:

Since the data retention for all requirements was the same in TOP-001-2, the data retention requirements for each requirement and measure were deleted and replaced with the following:

TOP-001-2, data retention: The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

TOP-002-3, M1. The Transmission Operator shall have evidence that it has assessed next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

Since the data retention for all requirements was the same in TOP-002-3, the data retention requirements for each requirement and measure were deleted and replaced with the following:

TOP-002-3, data retention: The Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

TOP-004-3, M2: Each Transmission Operator shall make available evidence that it has Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2. Such evidence could include but is not limited to a dated document with confirmation of the Agreement, such as a signature page or a memorandum of understanding, in electronic or hard copy format.

Organization	Yes or No	Question 7 Comment
NPCC	Yes	NPCC participant members agree provided that only the data specified is required to be dated, not the actual data.
Response: The SDT feels that your comment is covered in TOP-003-1, R1.2 which states “a mutually agreed upon format” between the two entities. The specifics of the request for information will be agreed upon by the parties involved and dated accordingly**.**		
Santee Cooper	No	OK with the measures and data retention with the exception of our concerns discussed in Question 12.
Response: Thank you for your response and please see the response to question 12.		

Organization	Yes or No	Question 7 Comment
SERC OC Standards Review Group	No	If the changes suggested above are agreed to by the SDT, please make the appropriate corresponding changes to the measurements.
Independent Electricity System Operator	No	We do not agree with some of the requirements (see above) and hence do not agree with some of the Measures. Other than that, we generally agree with the measures and retention periods for those requirements that we agree with.
Response: Please see the above responses.		
PJM Interconnection	No	TOP-003 M1-M5 - they all introduce a new requirement (i.e. the report be dated) - that requirement should be dropped from the measures.
Response: M1 **-** The SDT believes that it is imperative to have dated documentation pertaining to all reliability related information that is passed on between operating entities. This is particularly true whenever system upgrades/changes are done or equipment ratings are changed. Adding the word 'dated' to the Measure does not alter the requirement and is only common sense. M2 – M5: 'Dated' is only employed here with respect to the use of operator logs as a type of evidence. This does not alter the requirement in any fashion and is simply a common sense statement.		
Dominion - Electric Market Policy	No	TOP-001-2 @M4 - We don't agree with the underlying requirement (see comment to question 12). We do not agree with data retention requirements for M1 and M3 this standard. In our mind, there are two tenants that must be honored above all. The first is to follow reliability directives whenever possible, the 2nd is to provide data necessary for reliability assessments. Where an entity fails to comply, the requestor should immediately file a complaint with the region or NERC. We expect either of these to perform a prompt review. So, we don't see the need to keep data for a year nor do we see value in keeping data until next compliance audit when found non compliant. TOP-002-3 @ M3 should be removed as we do not agree with underlying requirement (see comment to question 12).
Response: The SDT feels your comment about TOP-001-2, M4 really pertains to TOP-001-2, R4. The SDT believes that this requirement is necessary in order to keep other entities appraised of the status of a generator or plant when that status can directly impact the reliability of the BES. In many cases the RC or BA is not directly responsible for voltage control in a particular area. The TOP in these cases would most likely be the responsible party for monitoring and responding to area voltage concerns. If the GOP were not to advise the TOP in these cases about unit voltage control capability changes it could certainly impact the reliability of the BES. The SDT does not feel that measures M1 and M3 of TOP-001-2 are only associated with conditions of non-compliance. The measures are there to insure that entities simply show that they either complied with a directive or offered emergency assistance. If they couldn't comply for any of the reasons stated in Requirements R1 or R3 of TOP-001-2 they can show proof as to the reason why. The data retention times for both of these measures seems agreeable by all other responders, therefore		

Organization	Yes or No	Question 7 Comment
the SDT will retain the retention periods as stated in the draft. The SDT feels your comment about TOP-002-3, M3 really pertains to TOP-002-3, R3. The SDT feels this requirement is necessary to insure all entities help in addressing a potential IROL limit and that each entity knows their specific role in the plan. The requirement and measures will remain as drafted.		
MRO NERC Standards Review Subcommittee	No	1. The measures seem to repeat the requirements perhaps this could be avoided since additional detail in the measures are not enforceable only the requirements are. 2. In the standard TOP-001-2 the retention period for requirement 5 and measure 5 is longer than required for R1 through R4, what is the reasoning for this? 3. In the standard TOP-001-2, there is no retention period given for requirement 6 and measure 6.4. In all of the standards and in the last sentence of the section "1. 4 Data Retention", isn't it extreme to retain "all" requested and submitted subsequent audit records? 5. In the standard TOP-002-3, requirement 3 depends on requirement 2 but these requirements don't have the same retention period, should they? 6. Measure 5 of the standard TOP-003-1 references requirement 9, shouldn't it reference requirement 5? 7. In the standard TOP-003-1, the retention periods for R4/M4 and R5/M5 are only for 90 calendar days but the rest of the requirements have a retention period for 3 years, shouldn't R4/M4 and R5/M5 have the same retention period as the rest of the requirements in this standard? 8. The MRO has concerns about storing large amounts of real-time data. In TOP-003-01, should R1, R4, and R5 data retention be set at 90 days? 9. In the standard TOP-004-3, M2's last sentence references the text "confirmation". What is needed for confirmation? Would a signature page be an example?
Response: 1. The SDT feels that the measures simply reinforce the requirements and explains what is needed for compliance. 2. The SDT has changed the data retention requirements in TOP-001-2 to the same timeframe (current calendar year plus previous calendar year) for all requirements for consistency purposes. **TOP-001-2, data retention:** The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~. 3. The SDT has changed the data retention requirements in TOP-001-2 to the same timeframe (current calendar year plus previous calendar year) for all requirements for consistency purposes.		

Organization	Yes or No	Question 7 Comment
4. The interpretation of the SDT on "all" requested and submitted subsequent audit records" means any supporting data required to be provided following a compliance audit. This would be a reasonable request, and that data should be kept with the original audit records. 5. The SDT agrees that all data retention requirements in TOP-002-3 should be the same. **TOP-002-3, data retention**: The Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. 6. The SDT has already taken care of this and the change has been made. Thank You for the comment. 7&8. The data retention periods for TOP-003-1 have been changed so that they are all the same - 3 calendar years (except for Requirement/Measure 1). The SDT feels a signature page would be acceptable and has changed the standard accordingly. **TOP-004-3, M2**: Each Transmission Operator shall make available evidence that it has Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2. Such evidence could include but is not limited to a dated document with confirmation of the Agreement, such as a signature page or a memorandum of understanding, in electronic or hard copy format.		
ITC Transmission	No	In TOP-001, the majority of retention requirements are current year plus one, except one is 3 years and one isn't specified. All retention requirements in this standard should be the same. In TOP-002 M1 add operating plans or guides as evidence that an assessment was performed. In TOP-002 retention requirements should be the same for all requirements.
Response: The SDT will change the data retention requirements in TOP-001-2 for all 6 requirements to the same timeframe for consistency purposes (current calendar year plus previous calendar year). **TOP-001-2, data retention:** The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~. The SDT feels that operating plans or guides are not required in TOP-002-3, M1. TOP-002-3, R1 simply states that the TOP needs to do an assessment for the next days operation to identify any potential SOL's . If there are no potential SOL's identified in the assessment then there is no need for plans or guides on how to address SOL's.		
ISO-NE	No	In general, TOP-001 is an event triggered standard. For example, a limit is violated and not corrected, an entity failed to followed a directive, etc.. Since it's impossible to prove the negative when there isn't an event, what these measures will

Organization	Yes or No	Question 7 Comment
		cause is entities to pass requests around to get statements from others to have something to show an auditor. TOP-003 It should be acceptable (rather that keeping evidence that each entity was sent a specification) that the specification be available to an accessible site and that the entities were made aware of its location. The measures should revolve around failure to obtain or provide data and either an event occurred or a complaint arose.
IRC Standards Review Committee	No	In general, TOP-001 is an event triggered standard. For example, a limit is violated and not corrected, an entity failed to followed a directive, etc.. Since it's impossible to prove the negative when there isn't an event, what these measures will cause is entities to pass requests around to get statements from others to have something to show an auditor. TOP-003 It should be acceptable (rather that keeping evidence that each entity was sent a specification) that the specification be available to an accessible site and that the entities were made aware of its location. The measures should revolve around failure to obtain or provide data and either an event occurred or a complaint arose.
Response: The SDT believes that all the measures in TOP-001-2 are appropriate and should easily be able to be complied with for auditing purposes. If an entity is asked to follow a directive or help in some way during an emergency those directives and conversations should be documented and most likely recorded. Even if there were not an event on the System, the SDT feels that all directives and requests between entities should be required to be written down at a minimum and therefore should be easy to retain for proof at a later time if needed. The SDT believes that mandating all entities to forward all required data specification information to one site is beyond the scope of the SDT. The measures do in fact revolve around failure to obtain or provide data. The SDT will make no changes to TOP-003 based on these comments.		
Manitoba Hydro	No	TOP-001-2. Data retention for all requirements should be the same. That is, current year plus the previous year.
Response: The SDT will change the data retention requirements in TOP-001-2 for all 6 requirements to the same timeframe for consistency purposes (current calendar year plus previous calendar year). **TOP-001-2, data retention:** The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.		
Ameren	No	There are inconsistencies in specified retention periods among several requirements. While we do not know the reason for this, we recommend that the SDT review the different retention periods and provide as much consistencies as possible.
Response: The SDT has reviewed the data retention requirements and made changes for consistency where necessary.		
Entergy Services	No	TOP-002-3 M1: We suggest a good example of compliance evidence be power flow models and study results instead of operator logs. If not, what does "assessment" mean in R1?

Organization	Yes or No	Question 7 Comment
Response: The SDT understands that the term assessment may mean different things to different entities. TOP-002-3, R1 indicates that the TOP needs to assess whether normal or Contingency conditions for the next day may exceed an SOL. Generally speaking this will only be known to the TOP through load flow studies and security analysis. TOP-002-3, M1 states "Such evidence could include but is not limited to dated operator logs or reports". As for the evidence, the SDT agrees that power flow outputs and study results are more appropriate and has made that change. **TOP-002-3, M1**. The Transmission Operator shall have evidence that it has assessed next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.		
AEP	No	Refer to question 3 response. The TOP-001-2 three year data retention for SOL violations seems excessive. Data that has been retained this long tends to lose its value. We would like to hear an argument from the SDT how this improves system reliability. Similarly, the three year data retention for distributing data specifications in TOP-003-1 (R2/M2, R3, M3) also seems excessive. We propose that the current and previous calendar years would suffice.
Response: The SDT will change the data retention requirements in TOP-001-2 for all 6 requirements to the same timeframe for consistency purposes (current calendar year plus previous calendar year). **TOP-001-2, data retention:** The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~. The data retention periods for TOP-003-1 have been changed so that they are all the same.		
Northeast Utilities	Yes	
American Transmission Company	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 7 Comment
Montenay Power Corp.	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery	Yes	
Duke Energy	Yes	
Response: Thank you for your comments.		

8. The SDT has included compliance elements including VSL for this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for change.

Summary Consideration:

Due to industry comments, the SDT has changed the following requirements, measures, and VSLs:

TOP-001-2, R1: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each reliability directive issued by the Transmission Operator, unless the respective entity informs the Transmission Operator that such actions would violate safety, equipment, regulatory or statutory requirements.

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

TOP-001-2, R4: Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination.

VSL

TOP-001-2, R1:

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements

TOP-001-1, R3, Severe VSL: The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements.

TOP-001-2, R4 VSL:

R4	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with 25% or less of the affected reliability entities unless conditions did not permit such coordination	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 25% or less than or equal to 50% of the affected reliability entities unless conditions did not permit such coordination	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 50% or less than or equal to 75% of the affected reliability entities unless conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 75% of the affected entities unless conditions did not permit such coordination.

TOP-001-2, R6 VSL:

R6	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on one occasion.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on two occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on three occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on four or more occasions.

TOP-002-3, R3 VSL:

R3	The Transmission Operator did not notify 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

TOP-003-1, R2 VSL:

R2	The Transmission Operator did not distribute its data specification to 25% or less of the entities that has Facilities monitored by the Transmission Operator or to 25% or less of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 25% and less than or equal to50% of the entities that have Facilities monitored by the Transmission Operator or to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 50% and less than or equal to 75% of the entities that have Facilities monitored by the Transmission Operator or more than 50% and less than or equal to 75% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 75% of the entities that have Facilities monitored by the Transmission Operator or more than 75% of the entities that provide Facility status to the Transmission Operator.

TOP-003-1, R3 VSL:

R3	The Balancing Authority did not distribute its data specification to 25% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 50% and less than or equal to 75% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 75% of the entities that provide Facility status to the Balancing Authority

Organization	Yes or No	Question 8 Comment
Santee Cooper	No	OK with the VSLs with the exception of our concerns discussed in Question 12.
Response: Thank you for your response and please see the response to question 12**.**		
SERC OC Standards Review Group	No	TOP-001, R4. We suggesting changing the words "affect and affected" to "impact and impacted", respectively.

Organization	Yes or No	Question 8 Comment
Response: The SDT has changed the requirement. **TOP-001-2, R4:** Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination.		
Dominion - Electric Market Policy	No	TOP-001-2R1 - Could be interpreted that non-compliance is based on number of occasions whereby entity invoked safety, equipment, regulatory, or statutory requirements as opposed to number of occasions whereby entity failed to comply with reliability directives. Suggest revising to read "?.did not comply with reliability directives issued by the Transmission Operator and did not inform the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, on one occasion." Suggest use of similar language for each Severity Level. R3 - Suggest revising to read "The Transmission Operator, Balancing Authority, or Generator Operator did not render emergency assistance to others, as requested and did not inform the requestor that such actions would violate safety, equipment, regulatory, or statutory requirements. R4 - Revise to conform to comment in question 12. TOP-003-1 R4 - Do not agree that a any failure to provide data warrants severe. Is reliable operations jeopardized for failure to report an outage on a 10 Mw peaking CT as it is for a 1000 Mw base load unit? We don't see them as the same and would rather see something akin to the following: Low - Failed to provide > 25% of data required Moderate - failed to provide 26-50% of data required High - Failed to provide 51-75% of data required Severe - failed to provide > 75% of data required

Response: On TOP-001-2, R1, the SDT agrees with your suggestion and has made conforming changes to clarify that noncompliance is based on a single occurrence where directions were not obeyed except in those cases where the TOP was not informed of safety, equipment, regulatory, or statutory requirements that prevented compliance with the directives. We also removed the Lower, Moderate and High VSLs at the suggestion of ITC Transmission.

TOP-001-2, R1 VSL:

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive

Organization	Yes or No	Question 8 Comment

				issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements.

:

On TOP-001-2, R3, the SDT agrees and has made conforming changes for the same reasoning as indicated in our response for TOP-001-1, R1, above.

TOP-001-1, R3, Severe VSL: The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements.

On TOP-001-2, R4: The SDT will ask a specific question of the industry on deleting the GOP from this requirement in the next posting.

On TOP-003-1, R4, the SDT thanks you for your comment, but does not agree. The intent of this requirement is to guarantee that the TOP will have all the data necessary to perform Real-time monitoring and reliability assessments. As such, the data that is requested is either supplied or it isn't, creating a binary situation. Attempting to divine 4 levels of non-compliance in a binary situation results in imprecise boundaries and increased auditor discretion, both of which lead to regulatory uncertainty, which is what the SDT is attempting to minimize.

Organization	Yes or No	Question 8 Comment
Bonneville Power Administration	Yes	I think TOP-001-2 R6 would be better to say the TOP "shall act to ensure mitigation of the magnitude?" thus eliminating extraneous phrasing "direct others".
Response: The phrase "ensure mitigation" potentially introduces new obligations on the TOP via the compliance process, e.g., how would we measure that the TOP "ensured mitigation" when the term "ensure" means to essentially guarantee in all situations? Therefore, the SDT did not change the language of Requirement R6.		
FirstEnergy	No	The VSL for TOP-001 R1 should all be revised to state, "? The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, and the respective entity failed to inform the Transmission Operator that such actions would violate safety, equipment, regulatory,

Organization	Yes or No	Question 8 Comment
		or statutory requirements on (one, two, three, four or more) occasion. " The VSL for TOP-001 R3 should be revised to state, "The Transmission Operator, Balancing Authority or Generator Operator did not render emergency assistance to others, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements. The VSL for TOP-001 R4 should be revised in a similar fashion to R1 and R3 above. The VSL for TOP-002 R3 as written implies that an entity that interacts with only one reliability entity would not receive a violation greater than "lower." In addition, as written these VSLs seem to allow the Compliance Auditor the opportunity to choose how to apply the VSL. As an example the entity with one reliability entity could be found to be guilty of a "Lower" violation because they missed their one reliability entity or they could be guilty of a "Severe" violation because they missed 100% of their reliability entities. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity. The VSL for TOP-003 R2 as written implies that an entity that interacts with only one data supplier would not receive a violation greater than "lower." In addition, as written these VSLs seem to allow the Compliance Auditor the opportunity to choose how to apply the VSL. As an example the entity with one data supplier could be found to be guilty of a "Lower" violation because they missed their one data supplier entity or they could be guilty of a "Severe" violation because they missed 100% of their data supplier entities. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity. The VSL for TOP-003 R3 has the same problem as R2. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity. The VSL for TOP-004 R1 states, "The Transmission Operator did not operate within an identified Interconnection Reliability Operating Limits(IROL) and the associated IROL Tv for any single occasion." This should be changed to state, "The Transmission Operator failed to mitigate an identified Interconnection Reliability Operating Limits (IROL) and within the allotted IROL Tv for any single occasion. " The VSL for TOP-004 R2 as written implies that an entity with only 1 tie line would not receive a violation greater than "lower." In addition, as written these VSLs seem to allow the Compliance Auditor the opportunity to choose how to apply the VSL. As an example the entity with one tie line could be found to be guilty of a "Lower" violation because they missed their one directly connected entity or they could be guilty of a "Severe" violation because they missed 100% of their directly connected entities. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity.

Response: On TOP-001-2, R1 and R3 VSL, the SDT made changes to accommodate industry concerns.

TOP-001-2, R1 VSL:

Organization	Yes or No	Question 8 Comment

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements

TOP-001-1, R3, Severe VSL: The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements.

On TOP-001-2, R4, the SDT cannot determine your intent as to why the VSL for R4 should be revised, because the comment indicates that it should be revised "in a similar fashion to R1 and R3", yet, R4 does not have the clarifying clause that was the subject of the comments in R1 and R3. Therefore, no change was made with regard to binary VSL but wording changes for clarity have been made.

TOP-001-2, R4 VSL:

R4	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not

Organization	Yes or No	Question 8 Comment			
	coordinate their respective operations known or expected to impact other reliability entities with 25% or less of the affected reliability entities unless conditions did not permit such coordination	coordinate their respective operations known or expected to impact other reliability entities with more than 25% or less than or equal to 50% of the affected reliability entities unless conditions did not permit such coordination	coordinate their respective operations known or expected to impact other reliability entities with more than 50% or less than or equal to 75% of the affected reliability entities unless conditions did not permit such coordination.	coordinate their respective operations known or expected to impact other reliability entities with more than 75% of the affected entities unless conditions did not permit such coordination.	

On TOP-002-3, R3 the SDT agrees and has made appropriate changes.

TOP-002-3, R3 VSL:

R3	The Transmission Operator did not notify 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

On TOP-003-1, R2 and R3, the SDT agrees.

TOP-003-1, R2 VSL:

R2	The Transmission Operator did not distribute its data specification to 25%	The Transmission Operator did not distribute its data specification to more	The Transmission Operator did not distribute its data specification to more	The Transmission Operator did not distribute its data specification to more

Organization	Yes or No	Question 8 Comment			
	or less of the entities that have Facilities monitored by the Transmission Operator or to 25% or less of the entities that provide Facility status to the Transmission Operator.	than 25% and less than or equal to50% of the entities that have Facilities monitored by the Transmission Operator or to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Transmission Operator.	than 50% and less than or equal to 75% of the entities that have Facilities monitored by the Transmission Operator or more than 50% and less than or equal to 75% of the entities that provide Facility status to the Transmission Operator.	than 75% of the entities that have Facilities monitored by the Transmission Operator or more than 75% of the entities that provide Facility status to the Transmission Operator.	
TOP-003-1, R3 VSL:					
R3	The Balancing Authority did not distribute its data specification to 25% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 50% and less than or equal to 75% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 75% of the entities that provide Facility status to the Balancing Authority	
On TOP-004-3, R1, the SDT feels the suggested wording is basically equivalent to what is already there so no change was made. On TOP-004-3, R2, the SDT is going to ask a question on the elimination of this requirement in the next posting so no changes have been made at this time.					

Organization	Yes or No	Question 8 Comment
MRO NERC Standards Review Subcommittee	No	1. For the TOP-001-2 VSLs for R1, these VSLs should be reworded because complying to the requirement would meet those VSLs. The MRO would suggest replacing "unless" with an "and" plus change the trailing text to read "? the respective entity did not inform the transmission operator ?". 2. For the TOP-001-2 VSLs for R2, what about the situation where the transmission operator did inform the RC and the affected TOP of a real-time emergency condition on an occasion but the notification was after the disconnection of switches? 3. For the TOP-001-2 VSLs for R4, what if the TOP or GOP does not coordinate because of system conditions. Is it possible that those entities might disagree as to what is a system condition? How would this disagreement be handled? 4. For the TOP-001-2 VSLs for R6, the timing is only one element of the evidence. These VSLs should be rewritten because the VSLs add to the requirement. The VSL should be changed to replace "the timing of when it acted" with "its actions" plus, add the text "when it" between the words "or" and "directed others".

Response: On TOP-001-1, R1, the SDT has made this change.

TOP-001-1, R1 VSL:

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate

Organization	Yes or No	Question 8 Comment

				safety, equipment, regulatory, or statutory requirements

On TOP-001-2, R2, the SDT removed the phrase from the requirement which should alleviate the concern.

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

On TOP-001-2, R4, the SDT believes that the respective entity makes the determination but that they must be prepared to defend their actions on a case by case basis.

On TOP-001-2, R6, the RTOSDT agrees with your comment and has made conforming changes.

TOP-001-2, R6 VSL:

R6	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on one occasion.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on two occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on three occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on four or more occasions.

Organization	Yes or No	Question 8 Comment
ITC Transmission	No	TOP-001 R1 Failure to follow a directive one even one occasion without reason should be treated as a severe VSL, similar to R3. TOP-002 R1 & R2 VSL should not be severe, there should be VSLs at all levels. It is not logical to have a severe VSL for not performing a day ahead analysis, and a Lower VSL for not following a reliability directive. TOP-004 R4 should have VSL for all levels, similar to R2,R3

Response: On TOP-001-2, R1, the SDT has made changes accordingly.

Organization	Yes or No	Question 8 Comment
TOP-001-2, R1 VSL:		

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements

On TOP-002-3, R1 and R2, the SDT agrees and has changed TOP-001-2, R1 VSL. .

In response to your final comment, there is no TOP-004-3, R4,

Organization	Yes or No	Question 8 Comment
ISO-NE	No	In general, these are binary requirements. An entity followed a directive or not, data was provided or it was not, a study was done or it was not. The true fix is to develop a sanctions matrix that deals with binary requirements rather than coming up with subjective ways to measure something that is yes/no. That said, we would not recommend spending a great deal of time making modifications, as there will most likely be an order directing modifications once the standard is filed.

Organization	Yes or No	Question 8 Comment
IRC Standards Review Committee	No	In general, these are binary requirements. An entity followed a directive or not, data was provided or it was not, a study was done or it was not. The true fix is to develop a sanctions matrix that deals with binary requirements rather than coming up with subjective ways to measure something that is yes/no. That said, we would not recommend spending a great deal of time making modifications, as there will most likely be an order directing modifications once the standard is filed.
Response: The SDT thanks you for your response.		
Manitoba Hydro	No	TOP-001-2 R5.. SOLs should be removed from the requirement and the VSLs.
Response: The SDT believes that the current wording is appropriate and no change was made.		
Ameren	No	1. For the TOP-001-2 VSLs for R4, what if the TOP or GOP does not coordinate because of system conditions. Is it possible that those entities might disagree as to what is a system condition? How would this disagreement be handled? 2. For the TOP-001-2 VSLs for R6, the timing is only one element of the evidence. These VSLs should be rewritten because the VSLs add to the requirement. The VSL should be changed to replace "the timing of when it acted" with "its actions" plus, add the text "when it" between the words "or" and "directed others".

Response: On TOP-001-2, R4, the SDT believes that the respective entity makes the determination but that they must be prepared to defend their actions on a case by case basis.

On TOP-001-2, R6, the RTOSDT agrees with your comment and has made conforming changes.

TOP-001-2, R6 VSL:

R6	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on one	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on two	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on three	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on four or

Organization	Yes or No	Question 8 Comment
	occasion.	occasions. occasions. more occasions.
Independent Electricity System Operator	No	a. We do not agree with some of the requirements, and suspect other commenters may express disagreements with some requirements. This may result in changes to the requirements and as such, the VSLs will need to be revised. b. A number of the VSLs proposed in the TOP standards, e.g. TOP-001, R1 and R2, are graded according to the number of repeated violations. This approach may need to be changed since recent FERC NOPR proposes that repeated violation is not to be the basis for different violation levels c. TOP-003, R1: It appears that missing one of the subrequirements is assigned a Low VSL, missing 2 of them is assigned a Medium VSL and missing all 3 or having no documented specification is assigned a Severe. We suggest to move the first 2 conditions to Medium and High.

Response:.

Understood.

The language of the requirement will determine if violations can be accumulated. If the requirement is plural, violations can be accumulated to assess the VSL. Without specific examples, the SDT cannot make specific changes.

On TOP-003-1, R1, the RTO SDT agrees with your suggestion and has made conforming changes.

TOP-003-1, R1:The SDT disagrees and has not made a change.

Organization	Yes or No	Question 8 Comment
Duke Energy	No	TOP-003-1 Requirement R5 VSLs should be patterned after the VSLs for Requirements R2 and R3, i.e. a graduated scale since R5 is not a binary requirement. TOP-002-3 Requirement R3 - if only one reliability entity is identified in plans to preclude exceeding an IROL, and that entity is not notified, which VSL would apply - "Lower" or "Severe"?

Response: The SDT continues to view Requirement R5 as a binary requirement, and did not change the VSLs per your suggestion.

On TOP-002-3, R3, the SDT has made changes to address your concern.

TOP-002-3, R3 VSL:

R3	The Transmission Operator did not notify 25% or less of the reliability	The Transmission Operator did not notify more than 25% and less than or	The Transmission Operator did not notify more than 50% and less than or	The Transmission Operator did not notify more than 75% of the

Organization	Yes or No	Question 8 Comment			
	entities identified in the plan(s) cited as to their role in the plan(s).	equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	reliability entities identified in the plan(s) as to their role in the plan(s).	
American Transmission Company	No	TOP-001-2 VSL: VSLs for R1 and R2 are written for when an entity does not follow a directive multiple times. Per FERC VSL should be based on the single non-compliance event. ATC suggest that the VSLs be re-written based on FERC guidelines. VSLs for R5 and R6 are based on the entity not having evidence of compliance not on the fact that they did not comply with the requirement. ATC suggest that the VSL be rewritten in order to address the requirement not the evidence to support the requirement. VSL for TOP-002-3 Requirement 3: If in a plan you identify one reliability entity and fail to notify that entity what is the VSL level that will be assigned. This seems to fall in both Lower and Severe. ATC believes that the VSL's should only have a single method for determining the VSL level in order to prevent conflicting determinations.			

Response: On TOP-001-2, R1, that SDT agrees and has made conforming changes to the VSLs. The language of the requirement will determine if violations can be accumulated. If the requirement is plural, violations can be accumulated to assess the VSL

TOP-001-2, R1: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each reliability directive issued by the Transmission Operator, unless the respective entity informs the Transmission Operator that such actions would violate safety, equipment, regulatory or statutory requirements.

TOP-001-2, R1 VSL:

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the

Organization	Yes or No	Question 8 Comment

				Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements

On TOP-001-2, R2, however, the SDT disagrees that this is a binary requirement and did not change the VSLs.

On the VSLs for TOP-001-2, R5 and R6, the SDT understands your concerns, but without evidence of action, how can one prove compliance? The SDT sees no conflict between the VSLs as worded currently and the requirements.

On the VSL for TOP-002-3, R3, the SDT has made a change to address your concerns.

TOP-002-3, R3 VSL:

R3	The Transmission Operator did not notify 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

Organization	Yes or No	Question 8 Comment
NPCC	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 8 Comment
PJM Interconnection	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your response.		

9. The SDT has provided an Implementation Plan with this posting. Do you agree with the implementation timeframes? If not, please provide specific suggestions for improvement.

Summary Consideration: The SDT feels that the Implementation Plan is well supported by the industry due to the fact there was only a single negative comment received. Therefore, the SDT will follow the timeframe for the Implementation Plan as drafted.

Organization	Yes or No	Question 9 Comment
SERC OC Standards Review Group	No	The SDT may want to consider a closer implementation date since there are no new requirements included in the proposed revisions to these standards.
Response: The RTO SDT feels the longer implementation dates are necessary in order to ensure that the projects mentioned in the prerequisites: Pre-2006, Operate within Interconnection Reliability Operating Limits; 2006-06, Reliability Coordination; and Project 2006-07, ATC/TTC/AFC and CBM/TRM Revisions have been approved prior to the implementation of this Project 2007-03, Real-Time Operations.		
Dominion - Electric Market Policy	Yes	While we agree with the SDT that all prerequisites must occur prior to implementation of this plan, we wish to cite, for the record, the sheer volume of draft standards that are now 'dependant' for prerequisite action on preceding drafts. We would like to see a moratorium on new drafts until the current back log is cleared. We are concerned that new drafts are being reviewed with the potential that ramifications of underlying/preceding drafts aren't being fully understood and/or that modifications made to any such drafts may not follow through in later draft standards predicated upon them.
Response: The SDT appreciates your concern but this is outside the scope of the SDT.		
NPCC	Yes	
Santee Cooper	Yes	
PJM Interconnection	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 9 Comment
FirstEnergy	Yes	
MRO NERC Standards Review Subcommittee	Yes	
ITC Transmission	Yes	
IRC Standards Review Committee	Yes	
Montenay Power Corp.	Yes	
PECO Energy		
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	
Oncor Electric Delivery	Yes	
Entergy System Planning & Operations (Gen & Mktg)	Yes	
Entergy Services	Yes	
Independent Electricity System Operator	Yes	We generally agree with the implementation timeframes that are dependent on the implementation of other standards. However, we reserve judgment on any specific issues that may arise when more definitive dates are proposed.
Duke Energy	Yes	

Organization	Yes or No	Question 9 Comment
AEP	Yes	
Northeast Utilities	Yes	
American Transmission Company	Yes	
ISO-NE	Yes	
Response: Thank you for your response.		

10. The SDT is recommending retirement of TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0. Do you agree with these retirements? If not, please provide specific reasons for your position.

Summary Consideration:

Due to industry comments, the following were changed:

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

TOP-003-1, Purpose: To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.

TOP-003-1, R1: Each Transmission Operator and Balancing Authority shall have a documented specification for data required to fulfill their respective responsibilities per the NERC Functional Model. The specification shall include:

TOP-003-1, R4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies).

TOP-003-1, M4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall make available evidence that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies) in accordance with Requirement R4. The data is limited to that needed by the Transmission Operator to support Operational Planning Analyses and reliability assessments. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

Organization	Yes or No	Question 10 Comment
NPCC	No	The note next to R4 in TOP-006 reads: "Load patterns now covered in the new TOP-005. Remainder not required for reliability." We understand that TOP-005 is to be retired, and we are unable to find the new TOP-005 that covers this requirement.
Independent Electricity System Operator	No	The note next to R4 in the red-line version of TOP-006 says: "Load patterns now covered in the new TOP-005. Remainder not required for reliability." Since TOP-005 is to be retired, we are unable to find a new TOP-005 that covers this requirement. Please explain the relevance of this note.
Response: TOP-006-1**:** There was a problem with the original posted material. You are correct; this is now covered under the data specification requirements of TOP-003-1.		

Organization	Yes or No	Question 10 Comment
SERC OC Standards Review Group	Yes	Although we agree with the retirements of TOP-005, 006, 007 and 008, the following discrepancies are noted: Top-006-1, R5 indicates this requirement has been removed to new TOP-005. TOP-005 is being eliminated and a new TOP-005 is not being developed. Where does this requirement reside? or is it really needed? TOP-008-0, R1 indicates this requirement has been moved to TOP-003-1, which is the standard for Operational Reliability Data. Should this read that it has been moved to TOP-004? Per-001-0, R1. We agree with the elimination of this Standard The authority of the system operator is mandated in FERC Order 693, paragraph 112.
Response: TOP-006-1**:** There was a problem with the original posted material. You are correct; this is now covered under the data specification requirements of TOP-003-1. TOP-008-0: There was a problem with the original posted material. As re-posted in the Implementation Plan, this should read: Deleted – now covered by TOP-001-2, R6 for IROL. Taking immediate steps for relief of all SOLs experienced or contributed to may not always be prudent, especially if other organizations are addressing the cause. In such cases, uncoordinated immediate actions may be counterproductive. Accordingly, requiring immediate action to relieve all SOLs was deleted in consideration of TOP-001-1 and TOP-004-3 requirements applied in combination. PER-001-0: Thank you for your response.		
Dominion - Electric Market Policy	No	We believe that the existing standards are more clear those contained in this draft. This draft seems to be trying to delineate TOP and BA standards/requirements from RC standards/requirements. In doing so, the draft loses the feeling of cohesiveness of the existing standards.
Response: The re-drafting effort is trying to delineate the RC vs. TOP/BA standards as was pointed out in the SAR for this project.		
Southern Company Transmission	No	Both TOP-001-1, R1, and PER-001-0, R1, were deleted. These standard requirements require operating personnel under the TOP and BA to have the responsibility and authority to implement real time actions to ensure the stable and reliable operation of the bulk electric system. Additionally, in paragraph 1330 of FERC Order 693, FERC approved PER-001-0 as mandatory and enforceable. Accordingly, FERC is clear in its intention that the operating personnel of the TOP and BA have authority to take action without any managerial approval being required. Also, in paragraph 1582 of the Order 693, FERC states R3 of Reliability Standard IRO-001-0 establishes the decision-making authority of the reliability coordinator, but not operating personnel of the TOP or BA. These facts stated above could be exposing a reliability gap if this standard is approved as written because the entities performing the TOP and BA functions must have the support of a NERC standard to be able to take immediate action without management approval or intervention. Reliability Standards Compliance programs are based on abiding by the NERC standards. By the TOP and BA not having clear decision-making authority from a NERC standard could lead to senior management of a company stepping in and requiring their approval before operating personnel are allowed to take action to alleviate problem. This could lead to jeopardizing

Organization	Yes or No	Question 10 Comment
		reliability. TOP-001-1, R2 has been deleted. It would seem logical that a requirement for the TOP to take immediate action to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc., would be worthy of being kept in the standard. If it is a duplication of an existing requirement, then please reference where the duplicate requirement is located.? Under TOP-001-2, R2 the phrase "including potential impacts caused by disconnections prior to switching" was added to the requirement. This addition seems to provide too much specificity and provides a very granular view for the requirement. It is best to remove this phrase and bring the requirement back to a higher level and end the sentence after "emergency conditions". It was noted that TOP-001-2, R3 replaces TOP-001-1, R6 and that the following component of the old R3 was deleted: "provided that the requesting entity has implemented its comparable emergency procedures". For an entity to render emergency assistance to another entity who has not implemented their own internal company emergency procedures prior to seeking help from others is not a wise decision. Deleting this phrase would create a burden on others providing the emergency assistance. Unless it can be shown there are other standard requirements already containing this required action, we recommend NOT removing this phrase.” Removal of the BA from requirement (TOP-002-2, R1) to plan operations into the future is not appropriate. Although it is agreed that CPS and DCS are much of the real-time basis for reliable operation, due to the physical requirements to start or even change output of many units, it is absolutely necessary that the BA plan a near-term operating horizon of several hours so that DCS and Energy Emergencies can be avoided. Removing the requirement for the BA to plan because DCS covers everything would be like removing the requirement for TOP to plan and just rely on the fact that the TOP has to correct SOL’s and IROL’s under TOP-004-1, R1 without any planning. Also, without this requirement to plan, under what basis would the BA have to request the generator output planning information currently in TOP-002-2, R15 that the SDT says will become part of TOP-003-1 data specifications? The Generator Operator could say there is no need for the BA to plan beyond what is needed for DCS and CPS and thus claim such requests are not needed. By removing this requirement the SDT has removed any basis for doing near-term planning. Similarly to the comment above for R1, the BA has a need to plan for the items covered in TOP-002-2, R5. Such a requirement should be included in the new R1 of TOP-002-3.? TOP-002-2, R8 requires the need to plan to meet Interchange Schedules and ramps, and should be carried forward to TOP-002-3. Even though INT-006 requires the BA to consider ramping capability in approving/denying Arranged Interchange, generation dispatch and unit capability can change significantly after an Arranged Interchange is approved. The BA must consider (i.e. plan) near-term ramps in being able to meet an upcoming Interchange ramp. The result of not planning for a ramp that can no longer be met is a frequency deviation. The ability to ramp is not a parameter in the BAL-

Organization	Yes or No	Question 10 Comment
		001 and BAL-002 standards. ACE is the basis for BAL-001 and BAL-002 and ramping capability is only one contribution to ACE and thus those standards should not be used as a reason for removing this requirement. In addition, the CPS criteria of BAL-001 are not granular enough (CPS1 is 12 month rolling average and CPS2 is a calendar month number) to manage real-time issues that can cause reliability problems. In the new TOP-003-1 which addresses reliability data needs, R2 and R3 require distribution to entities that provide Facility status. Why is the term status used? Why would not the distribution be to any entity that is the source of data under the specification R1 and not limit it to a Facility status source? In the mapping table of the Implementation Plan, TOP-006-1 R5, R6 and R7 were deleted with a reason given by the SDT that the monitoring activities are covered in the certification process. It is unclear how a one time verification of the activity during certification translates into a requirement that the monitoring processes continue and more importantly that violations have a penalty. It is recommended that these requirements be retained (and perhaps others deleted added back as well). Under TOP-004-3, R2 states that Agreements between TOPs are required for switching of BES tie lines. It is felt that this type of detailed information would be contained in the Interconnection Agreements between the two parties. Only when there are not existing Agreements in place would this requirement be necessary. In those cases where it is necessary, it is recommended that "specify switching" be replaced with "specify the procedures for switching". Under TOP-003-1, R4, the Balancing Authority should be added along with the Transmission Operator as receiving data as specified in R1. Requirement 1 requires the TOP and BA to have documented specification for data, and R4 requires the responsible entities to provide this data only to the TOP. If the BA is required to have the documented specification for data support, then the responsible entities should be required to provide appropriate data not only to the TOP but to the BA as well.

Response: TOP-001-1, R1 & PER-001-0, R1: Standards are written to a functional entity, not to individuals. How an organization meets the standard is entirely up to them.

TOP-001-1, R2: In the opinion of the SDT, TOP-004-3, R1 covers this issue.

TOP-001-2, R2: The SDT agrees and the phrase has been deleted.

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions**.**

TOP-001-2, R3: The SDT believes that there may be an issue here and will provide a specific question in the next posting to see what the industry thinks.

TOP-002-2, R1, R5 & R15: The SDT believes that in order for a BA to comply with CPS and DCS that they must plan and therefore a separate requirement is not required and would actually represent double jeopardy. The BAL standards cover these issues.

Organization	Yes or No	Question 10 Comment
TOP-002-2, R8: The SDT believes that your comment contains the answer to the question in that BAL covers ACE and ramping is part of ACE. TOP-003-1, R2 & R3: The SDT feels that the suggested wording is really equivalent and therefore no change was made. TOP-006-1, R5, R6, & R7: Performance to other requirements adequately covers the need to monitor and therefore no separate specific monitoring requirement is needed. TOP-004-3, R2: The SDT is asking a question in the second posting regarding the possible deletion of this requirement. TOP-003-1, R4: Due to your comments, the SDT has changed TOP-003-1 as shown below. **TOP-003-1, Purpose**: To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities. **TOP-003-1, R1**: Each Transmission Operator and Balancing Authority shall have a documented specification for data required to fulfill their respective responsibilities per the NERC Functional Model. The specification shall include: **TOP-003-1, R4**: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies). **TOP-003-1, M4**: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall make available evidence that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies) in accordance with Requirement R4. The data is limited to that needed by the Transmission Operator to support Operational Planning Analyses and reliability assessments. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.		
FirstEnergy	Yes	While we support the reduction in the overall number of standards, the deleted standards contained some requirements whose deletion we can not support. We have communicated these requirements and the issues surrounding them in the responses to other questions on this form including question 12 at the end of this form.
Response: Please see the response to question 12.		
Duke Energy	Yes	TOP-005-1 Requirement R2 has been deleted because it is not a reliability concern. Has this requirement been picked up in NERC Rules of Procedure or business practices? TOP-006-1 Requirement R4 is being deleted, and the comment says that load patterns are covered under TOP-005. But TOP-005 is also being deleted - is it intended that load data will be covered by TOP-003 now?
Response: TOP-005-1: The way that the standards have been re-written, data from the ISN is no longer being requested. TOP-006-1**:** There was a problem with the original posted material. You are correct; this is now covered under the data specification requirements of TOP-003-1.		
MRO NERC Standards	Yes	

Organization	Yes or No	Question 10 Comment
Review Subcommittee		
ITC Transmission	Yes	
IRC Standards Review Committee	Yes	
Montenay Power Corp.	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	
Oncor Electric Delivery	Yes	
AEP	Yes	
Northeast Utilities	Yes	
American Transmission Company	Yes	
Santee Cooper	Yes	
Entergy Services	Yes	
PJM Interconnection	Yes	
Bonneville Power Administration	Yes	
ISO-NE	Yes	

Organization	Yes or No	Question 10 Comment
Response: Thank you for your response.		

11. If you are aware of any regional variances or any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement that would be required as a result of these standards, please identify them here.

Summary Consideration:

No respondents cited any regulatory function, rule order, tariff, rate schedule. legislative requirement or agreement that would impact the revised standards.

Organization	Yes or No	Question 11 Comment
Dominion - Electric Market Policy	Yes	Typically, GO, GOP, PSE, LSE entities are prohibited from by federal and/or state Standards/Codes of Conduct from access to much of the information that would be required to perform any type of 'reliability assessment', determination of criticality or adverse impact. Only entities such as the RC, TO, TOP and perhaps BA have access to all the necessary information to make such determinations. For the GO, GOP, PSE, LSE entities, any such determination is really a business risk assessment, not a reliability assessment.
Response: The requirement is not for the GO, GOP, PSE, or LSE to perform a reliability assessment. The requirement is the aforementioned entities to supply operational data such as unit output, derates, total load, known interchange schedules, etc., in an agreed upon format and periodicity to the TOP who will perform the reliability assessment.		
MRO NERC Standards Review Subcommittee	Yes	
Response: Without a specific reference, the SDT is unable to respond to your comment.		
Bonneville Power Administration	Yes	WECC TOP-STD-007-0 would now need to link to TOP-004-3 (R1).
Response: That is an administrative matter for WECC and beyond the scope of the SDT.		
NPCC	No	
Santee Cooper	No	

Organization	Yes or No	Question 11 Comment
PJM Interconnection	No	
FirstEnergy		Not aware of any.
ITC Transmission	No	
IRC Standards Review Committee	No	
Manitoba Hydro	No	
Consumers Energy Company	No	
Ameren	No	
Oncor Electric Delivery	No	
Entergy Services	No	
Independent Electricity System Operator	No	
Duke Energy	No	
Northeast Utilities	No	
American Transmission Company	No	
ISO-NE	No	
Response: Thank you for your response.		

12. Are there any other issues that need to be addressed? Please be specific.

Summary Consideration:

In response to industry comments, the following were changed:

TOP-001-2, Purpose: To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

TOP-001-2, R3: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements.

TOP-001-2, R4: Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination.

TOP-001-2, M4: The Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among impacted reliability entities in accordance with Requirement R4 unless conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

TOP-001-2, Data Retention for R5: The Transmission Operator shall make available evidence for the current calendar year and one previous year that it has informed its Reliability Coordinator of actions being taken to return the System to within limits when an IROL or SOL has been exceeded in accordance with Requirement R5 and Measurement M5.

TOP-001-2, Data Retention for R6: The Transmission Operator shall make available evidence for the current calendar year and one previous calendar year of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv in accordance with Requirement R6 and Measurement M6.

TOP-001-2, R4 VSL	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with 25% or less of the affected reliability entities unless conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 25% or less than or equal to 50% of the affected reliability entities unless conditions	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 50% or less than or equal to 75% of the affected reliability entities unless conditions	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 75% of the affected entities unless conditions did not permit such coordination.

		did not permit such coordination.	did not permit such coordination.	

TOP-003-1, R4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies).

Organization	Yes or No	Question 12 Comment
Santee Cooper	Yes	TOP001-2 R2 the disconnections prior to switching portion of this requirement. Does this mean the RC and TOPs have to be called prior to switching in emergency situations? (e.g. a line is about to burn down) TOP004-3 R2 what is meant by Agreements in this context? An Agreement is a contract written or verbal. Do Interchange Agreements between TOPs fulfill this obligation? What is meant by synchronous BES tie line and should this be a defined term? Is this just to differentiate between AC and DC tie lines?
Response: TOP-001-2, R2**:** The SDT has changed the requirement to provide additional clarity as to intent. . **TOP-001-2, R2**: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions. TOP-004-3, R2**:** Agreement is a defined term in the NERC Glossary. The SDT will post a question in the next iteration on this topic.		
SERC OC Standards Review Group	Yes	We suggest eliminating R2 of TOP-004-3. An interconnection agreement between two entities will include this requirement.
Response: The SDT will ask a question on this topic in the next posting. .		
Dominion - Electric Market Policy	Yes	Generic comment - There appears to be a hieracy created by Reliability Standards with the RC being highest, followed by (equally?) the BA and TOP. If this is true, we'd prefer that the RC identify requirements necessary to enable it to meet its requirements under the standards. As new standards are being created, there appears to be the potential for some entities to have to provide the same information or have to coordinate actions with multiple entities but at different times, using different protocols. As examples:IRO-002-2 already requires the RC "to determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability

Organization	Yes or No	Question 12 Comment
		Coordinators." EOP-002-2 states "A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load." In order to meet this requirement, the BA will likely have to request GO/GOP to provided unit availability data (outages, derates) and the DP, TOP and/or LSE to provide load projections. This same information will likely be needed (and required) by the RC to perform its assessments. In this project TOP-001-008@ R4 states "Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to affect other reliability entities." and TOP-003-1@ R4 requires entities to provide data, as specified in Requirement R1, to its Transmission Operator(s). If these entities have provided the information required by their respective RC and the RC is required to coordinate with other RCs (IRO-014-1) there appears to be duplication which increases the workload of each entity and introduces opportunity for miscommunication or what may appear to conflicting submission of data (assuming that format and timeline differ). Specific commentsTOP-001-2 R3 - concern about ambiguity of phrase "to others", particularity from the GOP perspective. For reliability standards, the GOP should only be required to provide such assistance when so requested by its RC. Any other obligations should be included in the terms and conditions of its Interconnection Agreement with the TO or DP and, as such, is outside the scope of these standards. R4 - Concern about phrase "coordinate its respective operations known or expected to affect other reliability entities with those entities", particularly as it applies to GOP. GOP doesn't have access to data, nor the expertise, to make reliability assessments and may be precluded by Codes/Standards from coordinating with other entities. Suggest revising to require GOP to provide data as required by its RC to perform reliability assessments. Since GOP has to follow emergency directives issued by RC or TOP, there is nothing for the GOP to coordinate. If GOP actions or planned actions are deemed to have the potential to result in adverse impact to reliability, the RC or TOP should issue a directive to GOP to cancel such actions. TOP-002-3 - R3 should be deleted given that IRO-004@R3 states that "Each RC shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs." TOP-003R1.2 - Am concerned about the term "mutually agreeable format". Does the phrase 'mutually agreeable' apply to ALL applicable entities, or just the TOP and BA? Aren't there enough protocols and tools currently in existence (SDX, ICCP, RCIS) that the standard could at least address use of existing formats as opposed to 'mutually agreeable'? R4 - Does not require entities to provide data to BA although R1 requires BA to "?have a documented specification for data?.." and R3 requires each BA to "distribute its data specification to entities?". We suggest revising R4 to read "Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator and Balancing Authority." We removed the plural indicator as we believe that each entity's facility can be in only one TOP and BA area. If information relative to that facility is needed by multiple TOPs or BAs, those entities should share information. The entity should not be

Organization	Yes or No	Question 12 Comment
		required to submit data for the same facility to multiple reliability entities.
Response: Generic –The re-drafting effort is trying to delineate the RC vs. TOP/BA standards as was pointed out in the SAR for this project. TOP-001-2, R3 - The SDT has reviewed this requirement and made changes to provide clarity. BA's have been removed to avoid duplication with EOP-001-0, Requirement R1 and the GOP is essentially under the control of the BA and therefore isn't needed here. **TOP-001-2, R3**: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements. TOP-001-2, R4 – The SDT believes that the industry needs to weigh in on this topic and will ask a specific question in the next posting. TOP-002-3, R3 – The SDT disagrees and believes that it is important for the TOP to study its own system which may not be the same as what the RC studies as the objectives are different. No change made. TOP-003-1, R1.2 –The SDT believes the term "mutually agreeable" gives leeway for the reliability entities to exchange the required data and doesn't preclude any protocols. TOP-003-1, R4 – The SDT agrees with the inclusion of the BA and has changed Requirement R4 accordingly. The plurals are correct as multiple reporting requirements do exist and need to be accommodated in a national standard. If there is a single reporting requirement, then this wording remains intact and should not cause a problem. **TOP-003-1, R4**: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies).		
Southern Company Transmission	Yes	In the purpose statement the term "functional entities" is used. The term creates a confusion of terms between the purpose statement and requirements. Requirements 4 and 7 call for coordination among "other reliability entities" and "reliability entities" respectively. Therefore, recommend replacing "functional" with "reliability". The limits mentioned in TOP-001-2,R5 need more description. The recommended change is as follows: ?Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within the IROL limits when an IROL or SOL has been exceeded.? Requirement 7 of TOP-001-2 is duplicative as it applies to the TOP to that of standard IRO-005-2, R13. Could this result in a double jeopardy for non compliance with this requirement? In TOP-003-1, in the Purpose statement replace "system" with "System". In R1 of TOP-003-1, it is recommended that the term "specification" throughout the standard be replaced with a better term to describe what is meant in the standard. For example, the word "catalog" may be a better term. Also, it recommended that in the sub-bullet R1.3 the word "providing" should be replaced with "exchanging" .

Organization	Yes or No	Question 12 Comment
		In TOP-001-2, In section 1.4 of Data Retention the term "reliability entities" is capitalized. Should it be in lower case? On several requirements (e.g., TOP-006-1, R1;TOP-008-1, R1) recommended for retirement, there is a comment in the redline version stating that the requirement is covered in another standard. Upon reviewing the other standard, the requirement was not found. Was the latest version of the standard posted properly on the NERC website?
Response: 1 – The SDT thanks you for your comment and will replace 'functional entity' with 'reliability entity'. **TOP-001-2, Purpose**: To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES). 2 – The SDT believes the as written requirement is correct as it includes SOL or IROL limits, as appropriate, with the current wording. 3 – Your reference is incorrect, the standard cited has been updated and the correct reference is IRO-005-3, Requirement R10. Having said that, you are correct in your premise and TOP-001-2, Requirement R7 has been deleted. 4 – "System" is a defined term, but in the context of the Purpose statement "Transmission System" is not a defined term and therefore should not be capitalized. 5 – The SDT believes specification is the correct word. "Catalog" as suggested or "list, file, register, etc." is limiting in nature. Using the word "specification" augments the sub-requirements. The SDT finds providing and exchanging in this context to be basically equivalent and no change was made. 6 – The SDT thanks you for your comment. 'Reliability entities' is not a defined term and therefore should be lower case. TOP-006-1**:** This is now covered under the data specification requirements of TOP-003-1. TOP-008-1: As re-posted in the Implementation Plan, this should read: "Deleted – now covered by TOP-001-2, R6 for IROL. Taking immediate steps for relief of all SOLs experienced or contributed to may not always be prudent, especially if other organizations are addressing the cause. In such cases, uncoordinated immediate actions may be counterproductive. Accordingly, requiring immediate action to relieve all SOLs was deleted in consideration of TOP-001-1 and TOP-004-3 requirements applied in combination."		
Bonneville Power Administration	Yes	Good Ideas - thanks. However, do not see anything analogous to the current TOP-001 R1. and think we should retain something of this nature.
Response: The SDT thanks you for your comment but believes Requirement R1 of TOP-001-1 is not measurable. Furthermore, as identified in the Implementation Plan, the SDT does not feel that this requirement is needed in a Reliability Standard. Other standards already require the necessary actions. If this statement was intended to protect the operator from liability, it doesn't provide any real protection.		
FirstEnergy	Yes	1. In TOP-001-2 R2, the term "disconnections" is ambiguous. In addition, as written this requires the RC be notified prior to operator action. While we agree that we do not want operators taking actions that sacrifice accuracy for speed, we do not support the concept of approving all mitigation actions prior to implementation. Nor do we believe this concept serves to preserve or enhance reliability in situations where time is of the essence. The motivations behind the original requirements were 1) to preserve the reliability of the interconnection through recognition and mitigation actions and 2) to

Organization	Yes or No	Question 12 Comment
		ensure that removal of overloaded transmission facilities was done only when it preserved or enhanced reliability. We feel these two concepts should be managed as individual requirements similar to the requirements in effect today. The Drafting Team should include the system conditions of overload, abnormal voltage, and reactive conditions, and endangered equipment as system conditions permissible for action then communication. 2. In TOP-001-2 R3, the Drafting Team dropped the concept of the requesting entity implementing its comparable emergency procedures prior to an entity being required to lend assistance. This could lead to a request and requirement for TOp A to shed load in its area when TOp B, the entity requesting the assistance, has not shed load that would mitigate the emergency in its own area. This requirement should be revised to state, "Each Transmission Operator, Balancing Authority, and Generator Operator shall render emergency assistance to others, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements and provided the requesting entity has implemented its comparable emergency procedures. " 3. In TOP-001-2 R4, the Drafting Team preserved limiting the delay in notifications to system conditions. This change as written does not provide additional clarity as to which system conditions require and do not require notification in advance of action. This seems to make this Requirement too vague to be measurable. As currently proposed, this requirement means someone must decide which system conditions require and do not require advance coordination. Additional rules need to be developed by the team concerning the system conditions that require notification in advance of action. While we agree that we do not want operators taking actions that sacrifice accuracy for speed, we do not support the concept of approving all mitigation actions prior to implementation. Nor do we believe such a concept serves to preserve or enhance reliability in situations where time is of the essence. We recommend the drafting team restore TOP-001-1 R7.3 that states, "When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, GOp notifies TOp, TOp notifies RC and adjacent TOps at earliest possible time." As currently written this proposed requirement leaves it open for the operator to complete the mitigation actions prior to notifications taking place when system conditions do not permit such coordination which is inconsistent with the Drafting Team's action on other requirements, but is appropriate considering the potential system conditions. 4. In TOP-001-2 R5, the Drafting Team is supporting action in advance of communication, we support this stance. 5. The Drafting Team proposes to delete TOP-007-0 R3 that states, "A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2" because the authority already exists and does not need to be cited in a requirement. Other than the Reliability Standards, where does this authority exist? It seems that the drafting team intends to remove all requirements that provide for this authority in the Reliability Standards. We cannot support this stance. Without this provision in the standards, there is nothing to preclude an organization from requiring its operators to obtain approval from superiors within the organization prior to taking an action such as load shed, redispatch, reconfiguration, etc. that they know will preserve or enhance the reliability of the BES. While we agree these requirements do not provide any legal protection to the operator, they do enhance reliability of the BES by ensuring authority to act remains in the hands of the operator at the controls of the

Organization	Yes or No	Question 12 Comment
		System. 6. The Drafting Team deleted TOP-002-2 R1 because they feel the BA only needs to respond to CPS and DCS. Does the BA only have responsibility for responding to CPS and DCS? How does the TOp meet its obligations without BA assistance? How about MVAR support? It is not realistic to require a TOp to issue a reliability directive to a BA, GOp, GO, DP, etc. each time it needs some assistance in preparing a plan for future system conditions. We request the Drafting Team reconsider the application of the "BA only needs to respond to CPS and DCS" concept and instead apply the measure of reliability of the BES as the litmus test for requirements. 7. The Drafting Team deleted TOP-002-2 R2 as a good utility practice that is not measurable. We support this change since the TPL standards will support the interface between operations and planning. 8. The Drafting Team deleted TOP-002-2 R3 as the LSE and GOP are governed by their Interconnection Operating Agreements. We are concerned with relying on agreements as a sole means of providing for BES Reliability. Reliability related behavior is best governed by reliability standards. Therefore, we request the drafting team reinstate R3 of TOP-002-2. 9. In TOP-002-3 R1 and R2 the drafting team dropped the BA plan from the requirement. How will the TOP obtain information and assistance needed from the BA necessary to plan to meet scheduled system configuration in light of the fact that the work plan for these standards does not include any revisions to the BAL standards to require that support? 10. The Drafting Team deleted TOP-002-2 R7. With this deletion, how will the BA's plan for energy reserves insure its deliverability without TOp assistance? The implementation plan does not include any revisions to the BAL standards to verify deliverability. This deletion seems to segment the planning activities too much to ensure reliability. 11. The Drafting Team deleted TOP-002-2 R8 and R10. With this deletion, how does the TOp meet its voltage and reactive obligations without BA assistance? The implementation plan does not include any revisions to the BAL standards and CPS and DCS do not cover reactive support. What’s left in the standards to ensure reactive capacity is available on generating units to support voltage needs? 12. The Drafting Team deleted TOP-002-2 R18. This requirement should be retained and revised to state, "Neighboring BAs, TOps, TOs, use identical Tie- line names based on terminal end facility names when referring to transmission facilities. The purpose of this requirement is to ensure Company A and Company B are sure they are talking about the same Tie-line. 13. The Drafting Team deleted TOP-003-0 R1. This deletion eliminates the requirement for the GOp to provide outage data to the TOp. This requirement should be retained. 14. The Drafting Team has developed this standard based on the changes planned or proposed for other standards. This standard should not be finalized until all other standards that these changes are based on have been regulatory approved in order to avoid creating a reliability gap through deletion of an existing standard and the failed adoption of a proposed

Organization	Yes or No	Question 12 Comment
		standard. 15. TOP-004-3 R2 uses the term "Agreement" that is currently defined as "A contract or arrangement, either written or verbal and sometimes enforceable by law." Until the proposed revision to the definition of the term "Agreement" that would include "mutually agreed upon procedures and protocols" this requirement should be revised to state, "TOp has Agreements or mutually agreed upon procedures or protocols with directly interconnected TOps that specify switching of synchronous BES tie lines." 16. TOP-003-1 R1 be revised to state, "Each Transmission Operator, Balancing Authority, Generator Operator, Generator Owner, Transmission Owner, Purchasing-Selling Entity, Load Serving Entity, and Distribution Provider shall provide all data requested in writing by the Transmission Operator or Balancing Authority using the periodicity and in the format requested." With the adoption of this change, TOP-003-1 R2, R3, and R5 could be dropped because R1 covers all entities and data requirements. 17. In addition, with this change, the VRF for R1 should be changed to "High." The PSE should be added to the applicability of this requirement as they may have information that intermediary TOps need concerning large magnitude near-term sales and purchase power transfers that are unconfirmed with a high probability of implementation that should be studied by operations planners for potential impacts on the reliability of the BES. 18. The Drafting Team proposes to delete the TOP-006-1 R5, R6 and R7 as they are "covered by the certification process and no longer necessary." The certification program is being scaled back in part due to the reliability standards and the drafting team is removing requirements from the standards because the certification program covers it. We should not rely on programs outside of the reliability standards to provide for the reliability of the BES. These three requirements should be reinstated and revised to improve clarity and measurability.

Response: 1 – The SDT has modified TOP-001-2, Requirement R2 for clarity.

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

2 – The SDT is going to ask a specific question in the next posting on this issue.

3 – The SDT believes the requirement as written addresses when coordination is required with the statement of “operations known or expected to affect other reliability entities”. The SDT also believes it would be nearly impossible to list every scenario concerning conditions. Furthermore, the SDT believes statements such as “at the earliest possible time” and “as soon as possible” are not measurable. No change made.

4 – Thanks for your comment.

5 – The SDT believes this is covered in EOP-001-0, Requirement R3.3.

6 – The SDT believes DCS and CPS criterion is only applicable to the BA function. Furthermore, the SDT does not fully understand the premise of your question and

Organization	Yes or No	Question 12 Comment
does not see the parallel between your concern and TOP-002-2, Requirement R1. 7 – Thanks for your comment. 8 – This is addressed in TOP-003-1, R4. 9 – This is addressed in TOP-003-1, R5. 10 – This is addressed in TOP-003-1, R5. 11 – The SDT believes that this is already covered by VAR-001. 12 – This is being addressed by Project 2007-02: Operations Communications protocols. . 13 – This is addressed in TOP-003-1, R4. 14 – This is addressed in the proposed Implementation Plan. Note that in some Canadian jurisdictions, a standard becomes enforceable once the BOT approves a standard, subject to any delays identified in the associated Implementation Plan. 15 – The SDT may be deleting this requirement. A specific question will be raised in the next posting on this topic. 16 – The SDT believes that the current wording provides the flexibility needed to fulfill this task. No change made. 17 – The SDT doesn't believe that a specification falls within the definition of High VRF. The SDT believes that PSE data would be commercial data and not reliability data and has not made this change. 18 – TOP-006-1, R5, R6, & R7: Performance to other requirements adequately covers the need to monitor and therefore no separate specific monitoring requirement is needed.		
MRO NERC Standards Review Subcommittee	Yes	In standard TOP-004-3 and in section "1.5 Additional Compliance Information", what if you don't meet this reporting process? What will happen?
Response: The SDT believes having a reason to miss the reporting process also means you violated Requirement R1 of the standard and a penalty would be assessed.		
ITC Transmission	Yes	1. TOP-001 R2 the phrase "disconnections prior to switching" needs to be clarified. Does this refer to individual facilities or complete disconnection from an interconnection? 2. TOP-001 R3 It would be helpful to have a definition of 'emergency', recognizing this is a broader issue than just this standard. 3. TOP-003 R1 It is unclear who is this data exchange requirement is applicable to. By reading on to R2 and R3, one can assume the intended audience, however the requirement should be written to clear as a standalone item.

Organization	Yes or No	Question 12 Comment
		4. TOP-004 R1 This requirement should be incorporated into TOP-001, as it logically flows from the requirements there. This would facilitate possible eliminate of TOP-004 altogether. 5. TOP-004 R2 The phrase "specify switching" is unclear. Believe this is an unnecessary requirement as TOP-001 R4 already requires the coordination of operations.
Response: 1 – The SDT has removed this phrase. **TOP-001-2, R2**: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions. 2 –The SDT will use the word "emergency" as it is consistent with EOP standards. 3 – The SDT believes reading the requirements as a whole provides the clarity you are seeking. 4 – The SDT will evaluate this idea after the industry responds to the question on elimination of Requirement R2. 5 – The SDT will ask a specific question about eliminating this requirement in the next posting.		
ISO-NE	Yes	We appreciate this as a first effort in reducing the redundancy in the V0 standards. There should be some clarity in the use of the term SOL in these standards. According to the NERC Glossary, SOLs include both IROLs and local facility limits. These standards use SOL in the context of only a local facility limit. The temporary exceedance of local facility limit (within the time limitations of the rating) should not be construed to be a violation in these standards. Failure to correct a local facility limit to the point where it leads to an IROL or damages equipment should be a violation. Records should only be maintained if the local limit is exceeded and not corrected within the allowable time of the limit. The record keeping required for non-violations in these standards is unnecessary.
IRC Standards Review Committee	Yes	We appreciate this as a first effort in reducing the redundancy in the V0 standards. There should be some clarity in the use of the term SOL in these standards. According to the NERC Glossary, SOLs include both IROLs and local facility limits. These standards use SOL in the context of only a local facility limit. The temporary exceedance of local facility limit (within the time limitations of the rating) should not be construed to be a violation in these standards. Failure to correct a local facility limit to the point where it leads to an IROL or damages equipment should be a violation. Records should only be maintained if the local limit is exceeded and not corrected within the allowable time of the limit. The record keeping required for non-violations in these standards is unnecessary.
Response: While you are technically correct on the use of the terminology, actual review of the requirements doesn't indicate any need to change any of the wording used in the proposed revisions.		

Organization	Yes or No	Question 12 Comment
The SDT agrees that record keeping for non-violations is unnecessary.		
Indiana Municipal Power Agency	Yes	TOP-003-1 Requirement 4. Entities are to provide data, as specified in R1, to their Transmission Operators. Does R1.2 (mutually agreeable format) cover the entities who are reporting data to their Transmission Operators? If the request for data is not done on a regular basis, the entities in R4 need to receive a proper request from the Transmission Operator and be given time to gather the data. Neither R1 or R4 clearly address this process and the standard should address how the entities in R4 will be made aware of any specification of data needed by the Transmission Operator or Balancing Authority.
Response: The SDT believes the standard as drafted covers who needs to provide required data, in what format, and the timeframe and periodicity.		
Ameren	Yes	Standard TOP-004-3, section "1.5 Additional Compliance Information" - should this be included in R1/M1? Why is there a separate section at the end?
Response: This statement is dictated by the Compliance Guidelines. Because there is no impact to reliability if the report is not filed, the action of filing the report does not meet the criteria for an enforceable reliability requirement. Note that in accordance with the Sanctions Guidelines, if an entity fails to file the report as identified, then the Compliance Enforcement Authority may determine that the failure to report justifies a larger penalty than would otherwise be assessed.		
Entergy System Planning & Operations (Gen & Mktg)	Yes	The Implementation Plan refers to items in other proposed standards that will take the place of existing requirements, some of which are referred to by project number and others by standard number. In either case, the proposed standard that will contain the requirement should be presented or easily referenced. for example the propose IRO standards that will accommodate requirements moved from the TOP standards are not available for review and confirmation. Also, several requirements were deleted because they were "immeasurable". Some of these items should be revisited and determined if an alternative "measurable" requirement can be drafted. For example, it is important that an entity not continue operate in an unknown operating state (TOP-004 R3) and promptly return to an analyzed conditions/or perform an analysis for the current condition.
Response: The referenced standards and projects are all readily available on the NERC web site. To have included them in the Implementation Plan would have created an extremely large and unmanageable document. The SDT did look at alternative measures in each case and where requirements were deleted, decided that there was no suitable alternative.		
Entergy Services	Yes	1. Please expound upon the reasons why the SDT determined that TOP-002-2 R19 and TOP-004-2 R4 are unmeasurable. 2. TOP-001-2 R4 is going to be very difficult to measure. Any guidance the SDT can provide on how to demonstrate

Organization	Yes or No	Question 12 Comment
		compliance would be appreciated. 3. TOP-002-3 R3: The requirement that was mapped to this in the implementation plan used the phrase "shall coordinate." We think that R3, as written, is too vague. Also, it is more command and control versus a collaborative effort as implied by the previous use of "coordinate."

Response: 1 –TOP-002-2, R19 is unmeasurable because 'accurate' is not a measurable term. TOP-004-2, R4 is unmeasurable because 'valid' is a vague term.

2 – The SDT believes the criteria are identified in the Measures. Beyond that, the SDT can't provide compliance guidance.

3 – The SDT believes the requirements as drafted provide an appropriate level of reliability and places the responsibility on the TOP where it belongs. No change made.

Organization	Yes or No	Question 12 Comment
Duke Energy	Yes	1. TOP-001-2 Requirement R4, Measure M4 and VSLs for R4 : What does the word "affect" mean? Any operation by a TO or GO could have a slight affect on other reliability entities. The word "affect" should be qualified in some manner, to avoid a requirement to coordinate operations with negligible impact. We suggest using the phrase "have a reliability impact upon" instead of the word "affect". 2. TOP-004-3 Requirement R2, Measure M2 : What does "specify switching" mean? We suggest this wording be removed from the requirement. This requirement may have been moved from TOP-004-1 Requirement R6, but it is unclear. 3. TOP-008-0 Requirement R1 is being deleted. The Comment says that this is now covered by TOP-003-1, and in consideration of TOP-001 and TOP-004 requirements in combination. We think the Comment should not reference TOP-003-1. 4. TOP-002-2 Requirement R11 contains a requirement for a seasonal assessments to determine SOLs. Where is this requirement in the revised standards?

Response: 1 – The SDT has incorporated your suggested language.

TOP-001-2, R4: Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination.

TOP-001-2, M4: The Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among impacted reliability entities in accordance with Requirement R4 unless conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

TOP-001-2, R4 VSL	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not

Organization	Yes or No	Question 12 Comment

coordinate their respective operations known or expected to impact other reliability entities with 25% or less of the affected reliability entities unless conditions did not permit such coordination.	coordinate their respective operations known or expected to impact other reliability entities with more than 25% or less than or equal to 50% of the affected reliability entities unless conditions did not permit such coordination.	coordinate their respective operations known or expected to impact other reliability entities with more than 50% or less than or equal to 75% of the affected reliability entities unless conditions did not permit such coordination.	coordinate their respective operations known or expected to impact other reliability entities with more than 75% of the affected entities unless conditions did not permit such coordination.

2 – The SDT will ask a specific question in the next posting about deleting this requirement.

3 – The SDT made this correction in the revised Implementation Plan that was posted during the first comment period.

4 – The SDT believes reliability has been improved by requiring an assessment for next day operations and that this is as far out as a requirement needs to cover. You can always do more that the requirements. Longer term studies are done in planning and complement these assessments.

Organization	Yes or No	Question 12 Comment
AEP	Yes	The intent of TOP-004-03 R2 requires some clarification. It seems unnecessary to have an agreement for switching every BES tieline. It seems unlikely that every conceivable situation for switching a tieline could be covered in any type of agreement.
Response: The SDT will ask a question in the next posting about deleting this requirement.		
American Transmission Company	Yes	1. TOP-001-2 Requirement 2: First Concern: NERC Definition for Emergency: "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System" ATC's believe that anticipating an abnormal system condition that could result in an Emergency would be very difficult to certify compliance. It's our position that the requirement should be limited to actual Real-Time Emergency conditions. If the SDT disagrees than we request information on how a company could certify compliance on its ability to anticipate an emergency. 2. Second Concern: Currently the requirement requires notification of an automatic or immediate manual action prior to the action for an Emergency. We believe that notification prior to switching may put the system and/or equipment at a greater level of risk. The requirement should contain language that states notification should be done "if time permits"

Organization	Yes or No	Question 12 Comment
		otherwise it should be done following the action. 3. TOP-001-2 Requirement 4:What is the minimum level of "affect" that requires communication? 4. TOP-002-3 Requirement 1: Would a single assessment of next day's operation satisfy this requirement? or, Is the requirement asking for multiple next day operations to account for load changes expected throughout the day?
Response: 1 – The SDT studied your suggestion but feels that the requirement is clear as written and that your suggestion could result in a reduction in the reliability of the system. To the degree that an entity anticipates an Emergency, that information should be shared and this is what the requirement says. 2 – The SDT has changed the requirement to address your concern. **TOP-001-2, R2**: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions. 3 – The SDT will replace the word “affect” with “have a reliability impact upon”. **TOP-001-2, R4**: Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. 4 – There is only one assessment required but an assessment may require multiple studies. It is up to the entity to determine how many studies they must perform in order to assess of their next day operations		
NPCC	No	
PJM Interconnection	No	
Montenay Power Corp.	No	
Manitoba Hydro	No	
Consumers Energy Company	No	
Oncor Electric Delivery	No	
Independent Electricity System Operator	No	

Organization	Yes or No	Question 12 Comment
Northeast Utilities	No	
Response: Thank you for your response.		

Consideration of Comments on Second Draft of Standards for Real-Time Operations (Project 2007-03)

The Real-time Operations Standard Drafting Team thanks all commenters who submitted comments on the Second Draft of Standards for Real-Time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from April 7, 2009 through May 8, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 37 sets of comments, including comments from more than 130 different people from over 45 companies representing all 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Due to industry comments, a need to ensure the VSLs conform to the latest set of VSL guidelines, and continuing to respond to Order 693 directives, the following items have been changed:

- TOP-001-2: R2, R3, R4, R5 (added), R6 (added), R7, M2, M5 (added) M6 (added), R1-R8 VSLs
- TOP-002-3: R1, R2, M1, R1-R3 VSLs
- TOP-003-1, R1, R1 bullet #1, R4, R5, M4, M5, data retention for R4 & R5, R1-R5 VSLs
- TOP-004-3: R1 (moved to TOP-001-2, R5), R2 (delete)

The RTO SDT supports the following definition of Reliability Directive drafted by the Reliability Coordination SDT and capitalized the use of this term in TOP-001-2, Requirement R1 and associated measure and violation severity levels. (Comments on the definition are being solicited by the RTO SDT.)

> **Reliability Directive:** A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency

Due to the number of changes, the SDT is recommending a third posting.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Burns	Transmission Technical Operations	WECC	1
2. Tim Loepker	Dispatch	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Harry Tom	Project 2007-02 Operating Personnel Comm Protocols SDT	X	X			X				X	X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Lloyd Snyder	GSOC	SERC	1
2.	Tom Irvine	HydroOne	NPCC	1, 9
3.	Leanne Harrison	PJM	RFC	2
4.	James McGovern	ISO-NE	NPCC	2
5.	Fred Waites	Southern Company	SERC	1
6.	Harvie Beavers	Colmac Clarion/Piney Creek LP	RFC	5
7.	Alan N. Allgower	ERCOT	ERCOT	10

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	8.	Mark L. Bradley	ITC	MRO						1			
	9.	Mike Brost	JEA	FRCC						1			
	10.	William D Ellard	CAISO	WECC						2			
	11.	Wayne Mitchell	Entergy	SERC						1			
	12.	John Stephens	City Utilities of Springfield	RFC						1			
	13.	Ronald Goins	MISO	MRO						2			
3.	Group	Frank Koza	Real Time Best Practices Standards Study Group	X	X	X	X	X		X	X		
		Additional Member	**Additional Organization**	**Region**						**Segment Selection**			
	1.	Sam Brattini	KEMA	NA - Not Applicable						NA			
	2.	Charles Jenkins	ONCOR	ERCOT						3, 5, 1			
	3.	Frank Koza	PJM	RFC						2			
	4.	Francis Esselman	American Transm Co.	RFC						1			
	5.	Doug Rempel	Manitoba Hydro	RFC						1, 3, 5			
	6.	Mike Oatts	Southern Company	SERC						3, 5, 1			
	7.	Patti Metro	NRECA	NA - Not Applicable						1, 4, 7			
	8.	Mike Schiavone	National Grid	NPCC						3, 5, 1			
	9.	Jack Kerr	Dominion	SERC						3, 5, 1			
	10.	James Vermillion	AECI	SERC						1, 3, 5			
4.	Group	Patrick Brown	PJM's NERC and Regional Coordination Department		X								
		Additional Member	**Additional Organization**	**Region**						**Segment Selection**			
	1.	Albert DiCaprio	PJM	RFC						2			
	2.	Bill Harm	PJM	RFC						2			
	3.	Mark Kuras	PJM	RFC						2			
	4.	Tom Moleski	PJM	RFC						2			
	5.	Cathrine Wesley	PJM	RFC						2			

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	6. Susan McGill		PJM	RFC					2				
5.	Group	Jim Griffith	SERC OC Standards Review Group	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Phil Creech	Progress Energy Carolinas	SERC	1, 3, 5
2.	Paul Turner	Ga. System Operations Corp.	SERC	3
3.	Alisha Ankar	City of Springfield (CWLP)	SERC	1, 3, 5, 9
4.	Don Reichenbach	Duke Energy	SERC	1, 3, 5
5.	Jason Marshall	Midwest ISO	SERC	2
6.	Eugene Warnecke	Ameren	SERC	1, 3, 5
7.	Al McMeekin	SCE&G	SERC	1, 3, 5
8.	Vicky Budreau	Santee Cooper	SERC	1, 3, 5, 9
9.	Marc Butts	Southern Co Transmission	SERC	1, 3, 5
10.	Travis Sykes	TVA	SERC	1, 3, 5, 9
11.	Tim Hattaway	PowerSouth	SERC	1, 3, 5, 9
12.	Bob Thomas	IMEA	SERC	3, 5, 9
13.	Melinda Montgomery	Entergy	SERC	1, 3, 5
14.	Jim Case	Entergy	SERC	1, 3, 5
15.	Mike Clements	TVA	SERC	1, 3, 5, 9
16.	Steve Fritz	Aces Power Marketing	SERC	6
17.	Jalal Babik	Dominion Virginia Power	SERC	6
18.	Lee Taylor	Southern Co Transmission	RFC	1, 3, 5
19.	Mike Bryson	PJM	SERC	2
20.	John Troha	SERC Reliability Corp.	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dave Folk	FE	RFC	1
2. John Martinez	FE	RFC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	3. Andy Hunter		FE	RFC					1				
	4. John Reed		FE	RFC					1				
	5. Steve Megay		FE	RFC					1				
	6. Larry Hartley		FE Solutions	RFC					5, 6				
7.	Group	Jalal Babik	Dominion Resources Inc.	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
	1. Jack Kerr		Electric Transmission	SERC					1				
	2. Louis Slade		Electric Market Policy	RFC					6				
	3. Mike Garton		Electric Market Policy	NPCC					5				
8.	Group	Guy Zito	Northeast Power Coordinating Council										X
	Additional Member		Additional Organization	Region					Segment Selection				
	1. Ralph Rufrano		New York Power Authority	NPCC					5				
	2. Al Adamson		New York State Reliability Council	NPCC					10				
	3. Greg Campoli		New York Independent System Operator	NPCC					2				
	4. Roger Champagne		Hydro-Quebec TransEnergie	NPCC					2				
	5. Kurtis Chong		Independent Electricity System Operator	NPCC					2				
	6. Sylvain Clermont		Hydro-Quebec TransEnergie	NPCC					1				
	7. Manuel Couto		National Grid	NPCC					1				
	8. Chris de Graffenried		Consolidated Edison Co. of New York, Inc.	NPCC					1				
	9. Brian Evans-Mongeon		Utility Services	NPCC					6				
	10. Mike Garton		Dominion Resources Services, Inc.	NPCC					5				
	11. Michael Gildea		Constellation Energy	NPCC					6				
	12. Brian Gooder		Ontario Power Generation Incorporated	NPCC					5				
	13. Kathleen Goodman		ISO - New England	NPCC					2				
	14. David Kiguel		Hydro One Networks Inc.	NPCC					1				
	15. Michael Lombardi		Northeast Utilities	NPCC					1				
	16. Randy MacDonald		New Brunswick System Operator	NPCC					2				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	17. Bruce Metruck		New York Power Authority	NPCC					6				
	18. Robert Pellegrini		The United Illuminating Company	NPCC					1				
	19. Michael Schiavone		Nationa Grid	NPCC					1				
	20. Michael Sonnelitter		FPL Energy/NextEra Energy	NPCC					5				
	21. Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC					3				
	22. Gerry Dunbar		Northeast Power Coordinating Council	NPCC					10				
	23. Lee Pedowicz		Northeast Power Coordinating Council	NPCC					10				
9.	Group	Jason L. Marshall	Midwest ISO Stakeholders Standards Collaborators		X								
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Kirit Shah		Ameren	SERC					1				
10.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Carol Gerou		MP	MRO					1, 3, 5, 6				
	2. Neal Balu		WPS	MRO					3, 4, 5, 6				
	3. Terry Bilke		MISO	MRO					2				
	4. Joe DePoorter		MGE	MRO					3, 4, 5, 6				
	5. Ken Goldsmith		ALTW	MRO					4				
	6. Jim Haigh		WAPA	MRO					1, 6				
	7. Terry Harbour		MEC	MRO					1, 3, 5, 6				
	8. Jospeph Knight		GRE	MRO					1, 3, 5, 6				
	9. Scott Nickels		RPU	MRO					3, 4, 5, 6				
	10. Dave Rudolph		BEPC	MRO					1, 3, 4, 6				
	11. Eric Ruskamp		LES	MRO					1, 3, 5, 6				
	12. Pam Sordet		XCEL	MRO					1, 3, 5, 6				
11.	Group	Ben Li	IRC Standards Review Committee		X								

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
		Additional Member	**Additional Organization**	**Region**					**Segment Selection**				
		1. Anita Lee	AESO	WECC					2				
		2. Steve Myers	ERCOT	ERCOT					2				
		3. Patrick Brown	PJM	RFC					2				
		4. Lourdes Estrada-Salinero	CAISO	WECC					2				
		5. Charles Yeung	SPP	SPP					2				
		6. James Castle	NYISO	NPCC					2				
		7. Matt Goldberg	ISO-NE	NPCC					2				
		8. Bill Phillips	MISO	MRO					2				
12.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
13.	Individual	Hugh Francis	Southern Company	X		X		X	X				
14.	Individual	Mike Davis	WECC										X
15.	Individual	Frank Gaffney	FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool	X		X	X		X				
16.	Individual	Scott McGough	Oglethorpe Power Corporation					X					
17.	Individual	Chris Scanlon	Exelon	X		X		X	X				
18.	Individual	Michael J. Sonnelitter	NextEra Energy Resources, LLC					X					
19.	Individual	Harvie Beavers	Colmac Clarion					X					
20.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
21.	Individual	Jianmei Chai	Consumers Energy Company			X	X	X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
23.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
24.	Individual	Nied	Con Edison System Ops	X		X							
25.	Individual	Kasia Mihalchulk	Manitoba Hydro	X		X		X	X				
26.	Individual	Ed Davis	Entergy Services	X		X		X	X				
27.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
28.	Individual	Kirit Shah	Ameren	X		X		X	X				
29.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
30.	Individual	Gregory Campoli	New York Independent System Operator		X								
31.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
32.	Individual	Kathleen Goodman	ISO New England Inc.		X								
33.	Individual	Armin Klusman	CenterPoint Energy	X									
34.	Individual	Catherine Koch	Puget Sound Energy	X									
35.	Individual	Dan Rochester	Independent Electricity System Operator		X								
36.	Individual	Jason Shaver	American Transmission Company	X									
37.	Individual	Michael Ayotte	ITC Transmission	X									

1. TOP-001-2, R3: Regarding the requirement to provide emergency assistance - The SDT deleted the phrase "provided that the requesting entity has implemented its comparable emergency procedures" from the first iteration of the revised standard. Based on comments received from the first posting, the SDT is considering reinstating this phrase. Do you agree that this phrase should be reinstated?

Summary Consideration:

The vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard. Therefore, even though the SDT does not find any technical merit in restoring the phrase, the phrase has been placed back in the requirement.

Due to industry comments, the SDT has modified the following requirement:

TOP-001-2, R3: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Organization	Yes or No	Question 1 Comment
Midwest ISO Stakeholders Standards Collaborators	No	When a compliance audit is conducted, the compliance auditor will not be evaluating a third party TOP to determine if they implemented all of their comparable procedures prior to requesting emergency assistance. They will simply review if the TOP being audited responded to the request for emergency assistance. If they did not, they are not necessarily in violation of the requirement because the requirement does recognize legal restrictions for not responding. Thus, if a third party TOP requested the audited TOP to shed load but had not done so themselves, the audited TOP may have appropriately and compliantly refused because their state laws and regulations prevent them from shedding load for neighbors unless they are doing the same.
American Transmission Company	No	The Standard states that the TOP render emergency assistance as requested and available. There are other standards (EOP-001, EOP-005, EOP-008) that require an entity to implement its emergency procedures. If an entity does not implement emergency procedures when required it would be a violation. Adding a sentence here that requires the requesting entity to implement its comparable emergency procedures would be redundant to the other Standards.
Oglethorpe Power Corporation	No	
Xcel Energy	No	
Response: The SDT discussed the comment and understands the issues being presented but the vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard and the SDT has done so.		

Organization	Yes or No	Question 1 Comment
TOP-001-2, R3: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.		
WECC	No	Leave phrase deleted and current red line indicates that this is only TO to TO assistance, we believe this is too restrictive and reinstate BA's and GO's.
Response: The SDT discussed the comment and understands the issues being presented but the vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard and the SDT has done so. The Balancing Authority and Generator Operator must respond to reliability directives as per TOP-001-1, Requirement R1 so that assistance on a Balancing Authority –Transmission Operator or Generation Operator-Transmission Operator level is covered. **TOP-001-2, R3**: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.		
Entergy Services	No	There could be situations in which the TOP requesting support cannot implement comparable procedures. For instance, if reconfiguration from a neighboring system would resolve the situation, but reconfiguration on the requestor's system would not.
Response: The SDT does not consider comparable procedures to be identical operating actions. The SDT discussed the comment and understands the issues being presented but the vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard and the SDT has done so. **TOP-001-2, R3**: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.		
Independent Electricity System Operator	Yes	This phrase pre-supposes that the assisting TOP will need to implement emergency procedures in order to assist the requesting TOP. This may not always be the case if the assisting TOP is willing and able to provide assistance without any detrimental impact to its own system. If such an arrangement were to be permitted, the details would be covered in Operating Agreements between the two entities. The SDT may therefore wish to consider catering for this and other possibilities by appending the clause subject to the provisions of operating agreements where established?
PJM's NERC and Regional Coordination Department	Yes	PJM supports the intent and the concept of comparability as intended by this requirement. However, PJM would note that TOP Emergency Procedures are not identical and are designed around the reliablity needs and capabilities of the individual TOP. When dealing with compliance, the interpretation of what is and what is not comparable could have unintended consequences.

Organization	Yes or No	Question 1 Comment
SERC OC Standards Review Group	Yes	Also, it is not clear in the context of TOP-001 what kinds of assistance an operator of transmission should give to another Transmission Operator (for example, refer to EOP-001, R1 for clarification)
FirstEnergy Corp	Yes	We support reinstating the proposed text and it should be clarified, provided that it can be shown that the action requested to assist the other party will mitigate an adverse reliability problem. FE suggests that the text should indicate provided that the requesting entity has implemented its comparable emergency procedures capable of lessening or mitigating the impact of the emergency and that the assistance requested will help to alleviate an adverse reliability problem.
Dominion Resources Inc.	Yes	As currently written an entity could be found non-compliant for not providing emergency assistance to a requesting entity that is not willing to help itself. That punishes the wrong party.
Northeast Power Coordinating Council	Yes	It is expected that further details of emergency assistance to be provided would be covered in Operating Agreements.
Southern Compnay	Yes	Yes, the phrase should be reinstated. Also, these actions should be coordinated by the Reliability Coordinator(s). Thus, we believe the verbiage should ultimately be: provided that the requesting entity has implemented its comparable emergency procedures as coordinated by the Reliability Coordinator(s).
FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool	Yes	This is a tough one to answer, there are conceivably two types of timelines for emergencies, e.g., an emergency where response is required within minutes vs. response during a longer period of time. If a response is needed in minutes, such as post-contingency with a facility within a 10 minute emergency rating, there may be no time for a sequential step-by-step process where deleting the phrase is appropriate and entities will need to trust that the TOP is making the correct decisions. If there is time, such as a pre-contingency forecast that an element may exceed a rating, but the contingency has not occurred, then a step-by-step sequential process where the TOP in an emergency state takes action first is more appropriate. How about something like: provided that, time permitting, the requesting entity has implemented its comparable emergency procedures. Of course this introduces the difficult to measure time permitting, but maybe this could be clarified as pre-contingency vs. post-contingency
American Electric Power	Yes	AEP would suggest that the phrase be reinstated with a change of the word implemented to taken into consideration. It is important that entities not solely rely on emergency assistance when alternatives may be available. The timing itself may necessitate alternative approaches.
Consumers Energy Company	Yes	An Entity can not be required to take actions for another if the requesting entity has not taken all steps available to them to correct the situation.

Organization	Yes or No	Question 1 Comment
Con Edison System Ops	Yes	I justify this by saying that this phrase should already included in an operating agreement between the TO's. ...but, having this wording in the standard as well will serve to ensure that TO's have their documents and agreements up to date.
Oncor Electric Delivery	Yes	This phrase should be reinstated.
Manitoba Hydro	Yes	
Duke Energy	Yes	
Ameren	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
New York Independent System Operator	Yes	
ISO New England Inc.	Yes	
Puget Sound Energy	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Subcommittee	Yes	
IRC Standards Review Committee	Yes	
PacifiCorp	Yes	
NextEra Energy	Yes	

Organization	Yes or No	Question 1 Comment
Resources, LLC		
Colmac Clarion	Yes	
E.ON U.S.	Yes	

Response: Thank you for your response. The vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard and the SDT has done so.

> **TOP-001-2, R3**: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.

2. TOP-001-2, R4: Regarding the requirement to coordinate operations – Based on comments received from the first posting, the SDT is considering deleting the GOP from this requirement. Comments were received questioning the role of the GOP in reliability analysis beyond providing the data in TOP-003-1, Requirement R4. Do you agree that the GOP should be deleted from this requirement?

Summary Consideration: There was no consensus on the removal of the Generator Operator; therefore, the SDT agrees to retain the Generator Operator in TOP-001-2, R4.

Organization	Yes or No	Question 2 Comment
FirstEnergy Corp	No	TOP-001-2 R4 requires the actions of the GOP be coordinated with impacted entities while TOP-003-1 R4 requires the GOP to provide data to the TOP and BAs. These are two completely different aspects of the BES operation and both need to be addressed by a standard.
Northeast Power Coordinating Council	No	We believe there are occasions when a GOP may need to take actions that would require coordination with or notification of the RC/TOP/BA or others who could be impacted. At this time it is not clear what other standards could obligate the GOP to do so if the GOP were removed from this requirement.
IRC Standards Review Committee	No	We believe there are occasions when a GOP may need to take actions that would require notification to the RC/TOP/BA or others who could be impacted. This is not following directives; it is for the GOP to make known to others of actions it will take that can have a reliability impact or affect others. If a predetermined list of actions to be communicated is established, then this requirement is not needed. At this time it is not clear what other standards provide this list which collectively obligates the GOP to notify parties that would be impacted. If the requirements for a GOP to communicate and coordinating actions such as removing AVR from service, derating real and reactive capabilities, removing units, protective relays, stabilizers, exciters, etc. out of service, are covered by other standards, then we do not disagree with the proposed deletion.
Southern Company	No	The GOP needs to communicate problems that could impact normal operation.
E.ON U.S.	No	The requirement should state that the Generator Operators should be required to coordinate with their respective TOP not simply provide data.
Entergy Services	No	The status of large generators can have a reliability impact on other reliability entities, and they should be included in this standard.
Duke Energy	No	We believe it’s critical for the GOP to coordinate operations with the TOP.

Organization	Yes or No	Question 2 Comment
Ameren	No	GOPs need to coordinate their activities. For instance, a small tube leak might not mandate an immediate outage for a plant electrically near a known SOL/IROL area. To the extent the GOP and TOP coordinate when the outage to repair this condition will occur, BES reliability benefits.
Brazos Electric Power Cooperative, Inc.	No	If a GOP is to comply with directives from a TOP in R1, then a requirement "to coordinate operations" is needed in R4.
New York Independent System Operator	No	We believe there are occasions when a GOP may need to take actions that would require coordination with or notification of the RC/TOP/BA or others who could be impacted. At this time it is not clear what other standards could obligate the GOP to do so if the GOP were removed from this requirement.
Con Edison System Ops	No	The GOP wording should remain.
Independent Electricity System Operator	No	TOP-001-2 R4, as written, stipulates the need for coordination of operations, i.e., coordination with or notification of the RCs/TOPs/BAs or others who could be impacted by the GOPs actions and operational plans. This is more than merely providing data, which is covered by TOP-003-1 R4.On the latter requirement (TOP-003-1, R4), we are unable to find an explanation for the addition of .including, but not limited to: and the bulleted items that follow. It suggests that only the listed information needs to be provided. Requirement R1.1 would serve the intended purpose by simply saying: A list of required data to be exchanged. We suggest deleting the added wording and bullets.
American Transmission Company	No	This requirement does not get into the specifics of what is required of the GOP other than to state that it shall coordinate its operations, which is an important function. TOP-003-1 requires specificity regarding data exchange which is a different and more specific scope than TOP-001-2 R4. The two requirements are very different in scope and are, therefore, not redundant.
Response: There was no consensus on the removal of the Generator Operator; therefore, the SDT agrees to retain the Generator Operator in TOP-001-2, R4.		
Midwest ISO Stakeholders Standards Collaborators	No	What if the unit is a reliability must run unit? With this requirement in place, the GOP may be more proactive in keeping the unit running (i.e. willing to take a greater risk damaging the unit if there is already a problem with the unit). Without the requirement, the GOP may shut the unit down at the first sign of any problem.
ITC Transmission	No	Generators have an important role in supporting BES reliability and that should be recognized. Taking a unit offline, particularly a must-run unit, should be coordinated with the TOP.
Response: The SDT has agreed to retain the Generator Operator. The SDT believes that the specific issue mentioned in your comments related to a reliability-		

Organization	Yes or No	Question 2 Comment
must-run generator's failure to coordinate operations is a contractual issue rather than a reliability issue.		
SERC OC Standards Review Group	No	
WECC	No	
Consumers Energy Company	No	
Response: Thank you for your response.		
PJM's NERC and Regional Coordination Department	Yes	The data obligations for GOPs to coordinate with its TOPs is covered in TOP-001-2 R1. The operational obligations for GOPs to coordinate with TOPs is covered in IRO-005. IRO-005-3 R1 places a requirement on the RC to have access to operating data (which specifically includes planned generation outages R 1.9). Thus the RC already has the responsibility to get the data in question. Given that the RC has the authority to request and obtain that data, one could argue that there is no need to also mandate that the GOP coordinate the same data, since that obligation already lies with the RC - see R4).
Dominion Resources Inc.	Yes	We support the change. FERC Codes/Standards of Conduct prohibit transfer of non-public transmission information to "marketing entities". Most staffs on the "transmission side" of the industry (TO, TOP, TP, RC) are reluctant to share any non-public information with those on the "generation side" (GO, GOP) because they are unsure whether or not those staffs are deemed "marketing entities".
FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool	Yes	Yes, it is appropriate to delete GOP from this requirement. However, consider adding a bullet under TOP-003-1 R1.1 that includes planned and unplanned generator capacity changes (which is then referred to in R4), similar to the current TOP-002-2, R14.1.
Colmac Clarion	Yes	Particularly since R2 contains no requirement for communications concerning notification of any problems or communication with the GOP. Likely the first time GOP will be aware of condition is at failure of RC/TO efforts to resolve same.

Organization	Yes or No	Question 2 Comment
American Electric Power	Yes	AEP appreciates the removal of redundant requirements, where possible to do so. We do not see the need for the GOP to be involved.
Oncor Electric Delivery	Yes	GOP should be deleted from this requirement.
ISO New England Inc.	Yes	We believe this is covered by various other requirements in various other standards and need not be maintained here.
Oglethorpe Power Corporation	Yes	
Exelon	Yes	
NextEra Energy Resources, LLC	Yes	
Manitoba Hydro	Yes	
Xcel Energy	Yes	
Puget Sound Energy	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Response: Thank you for your response. The SDT agreed to retain the Generator Operator as described in the summary response.		

3. TOP-001-2, R5: Regarding SOL exceedance notification – The consensus of the industry in the first posting was that some subset of SOLs needs to be reported but there was no clear cut agreement on what subset to report to the RC. The subset of SOLs to be reported must be easily identifiable and measurable while supporting reliability. Please remember in your response that as per the NERC Glossary that IROLs are a subset of SOLs. Given that requirement, what subset of SOLs do you feel need to be reported?

Summary Consideration: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has added TOP-001-1, Requirement R6 and modified TOP-001-1 Requirement R7 to require a subset of SOLs to be reported to the RC.

TOP-001-2, R6. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability.

TOP-001-2, R7. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	System Operating Limits are meant to ensure operation within acceptable reliability criteria. Understanding that there is a subset of more critical SOL's defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances which can be accomplished via SCADA or other means of action and communication when necessary.
ISO New England Inc.	No	System Operating Limits are meant to ensure operation within acceptable reliability criteria. Understanding that there is a subset of more critical SOL's defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances, either through SCADA or other means. This should ensure keeping an eye on SOLs so that cascading into an IROL will not occur.

Response: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has added TOP-001-1, Requirement R6 and modified TOP-001-1 Requirement R7 to require a subset of SOLs to be reported to the RC.

TOP-001-2, R6. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability.

TOP-001-2, R7. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.

There is nothing in the standard that precludes you from reporting all SOL exceedances to the Reliability Coordinator and SCADA may be used to accomplish this task but the SDT does not feel that it is either warranted to spell out a specific method or to report all SOLs.

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Subcommittee	No	IROLs are a sufficient subset to report.
Manitoba Hydro	No	IROL's only
IRC Standards Review Committee	No	(Please note that CAISO abstained from the following comments) System Operating Limits are meant to ensure operation within acceptable reliability criteria. We understand that IROL is one subset of the SOL's but there is another subset of SOLs that either have special relevance to the TOP, or though not determined to be IROLs at the onset, would have an adverse impact on interconnected system reliability if their exceedances are not mitigated or are simply ignored. We believe the TOPs are in the best position to determine this subset, subject to the concurrence of its Reliability Coordinators.
PacifiCorp	No	PacifiCorp has no specific subset of SOLs to suggest, however, they must be clear and easily identifiable and measurable. Suggested subsets should be included in the next comment phase for this SAR.
WECC	No	All SOL's should be reported to the RC
E.ON U.S.	No	All SOL exceedances on the BES should be reported to the RC and corrective actions should be coordinated with the RC.
New York Independent System Operator	No	System Operating Limits are meant to ensure operation within acceptable reliability criteria. Understanding that there is a subset of more critical SOL's defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances.
Bonneville Power Administration		No preference, we report identified WECC rated paths.
NextEra Energy Resources, LLC		No comment.
PJM's NERC and Regional Coordination Department		PJM agrees that reporting should be based upon and restricted to reliability issues. Given the broad scope of the term SOL as defined in the NERC Glossary, PJM agrees that the requirement should be limited to a subset of the SOLsPJM proposes: 1. The TOP requirement on limit reporting parallel the RC requirement on IROLs 2. The TOP report violations (not exceedences) of any limit predefined by the TOP to be an essential limit (i.e. for a defined local condition that is deemed by the TOP to be of special concern and is not covered by any

Organization	Yes or No	Question 3 Comment
		predefined IROL). This approach provides a TOP the flexibility, when appropriate, to go beyond the definition of BES and to use reliability considerations rather than arbitary formulae to drive its operational reporting.
Midwest ISO Stakeholders Standards Collaborators		All SOL exceedances should be reported to the Reliability Coordinator. The Reliability Coordinator has the ultimate reliability authority. If the RC is not made aware of an SOL exceedance, how can the RC evaluate if the exceedance is actually approaching an IROL? Further, multiple SOL exceedances can be a sign of a greater reliability problem that the RC needs to rectify.
Southern Company		The subset will be pre-contingency IROL exceedences, post-contingency IROL exceedences, and real-time facilities experiencing SOL exceedences.
Con Edison System Ops		Let me start out by saying that ConEd reports all SOL's that occur on its system to the NYISO, our RC/BA/TOP.Only those SOL's should be reported to a higher authority (NPCC and above) that result from the TO operating its system in a state which is not allowed. That is, real time SOL's that arise from the TO operating its system on a post-contingency basis due to an exception granted by its RC should not be reported.
Entergy Services		Instances where an IROL is exceeded should be required to be reported to the RC. It should be left to the RC and TOP to agree to other SOLs that are important enough to be required to be reported to the RC.
ITC Transmission		At a minimum, the Transmission Operator should report any SOL that has exceeded or is expected to exceed 30 minutes.
SERC OC Standards Review Group	Yes	The subset of SOLs, other than IROLs (which must be reported), should be agreed upon between each Reliability Coordinator and the TOPs within the RCs reliability area.
FirstEnergy Corp	Yes	The question as written does not lend itself to a yes/no answer, the selection of yes was made to indicate that we agree some subset of SOL, when exceeded, warrants the a TOP notification to the RC. FE believes that the appropriate subset are those SOLs that are associated with a previously defined Interconnection Reliability Operating Limit (IROL) as determined via the FAC-014 reliability standard.
Dominion Resources Inc.	Yes	In addition to IROLs, the subset of SOLs that need to be reported should include any other SOL exceedances that the RC requests notification of and, in the Eastern Interconnection, any other SOL exceedances associated with permanent, reliability flowgates as defined in the NERC Book of Flowgates.
FMPA and its All Requirements Project Participants, as follows:	Yes	We assume “Yes” means we agree that a subset of SOLs should be reported. First, any voltage stability and transient stability limited SOLs should be reported. Second, for thermally limited SOLs, an equipment voltage

Organization	Yes or No	Question 3 Comment
Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool		class threshold for the facility with the thermal limit is probably the easiest to implement, e.g., > 200 kV, and seems consistent with other standards with this threshold (e.g., PRC 023, FAC-003). We are a bit confused with handling of IROLs, IRO-009-1 seems to make the RC responsible for managing IROLs, and therefore, no reporting of IROLs seems to be needed in TOP-001-2; hence, should SOLs that are IROLs be reported?Note that there seems to be a conflict between this requirement and the requirements of IRO-009-1, e.g., both the TOP and the RC are being held accountable to managing IROLs. This arrangement seems fraught with potential for confusion. We believe only one entity ought to be responsible for managing IROLs, and that entity should probably be the RC. This comment applies to R6 of TOP 001 2, and this comment also applies to the conflict between TOP-004-3 R1 and IRO 009-1 R4, which assign the responsibility of operating within IROL limits to both the RC and TOP. Who has primary responsibility? Who takes leadership in a situation? Is RC primary with TOP back-up?
American Electric Power	Yes	While it is expected that the Transmission Operators work in conjunction with the Reliability Coordinators to mitigate most SOL violations, a NERC requirement to report all SOL violations seems impractical. The IROLs provide a clear and logical subset of SOLs that should be reported to the RC.
Oncor Electric Delivery	Yes	Comments: Report all SOLs that require firm load to be dropped to return transmission elements within limits.
Duke Energy	Yes	Given that geography varies, system interdependencies and ratings philosophy, TOP/RC should agree on what to report.
Brazos Electric Power Cooperative, Inc.	Yes	The IROL subset needs to be reported.
Puget Sound Energy	Yes	Interconnections or major paths as specified by the region only
Response: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has added TOP-001-1, Requirement R6 and modified TOP-001-1 Requirement R7 to require a subset of SOLs to be reported to the RC. **TOP-001-2, R6**. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability. **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.		
Independent Electricity System Operator	No	System Operating Limits are meant to ensure operation within acceptable reliability criteria. Understanding that there is a subset of more critical SOL's defined as IROLs, we suggest that the TOP should inform the RC of all

Organization	Yes or No	Question 3 Comment
		SOLs and the actions being taken to address the exceedances.Further, this question runs counter with the SDT's proposal/decision to remove the requirement for the TOP to operate within SOLs from TOP-004-2, R1, to which we expressed a strong disagreement when commenting on the last posting. If there is no requirement for the TOP to operate within SOLs, then what purpose would it serve for the TOP to report exceeding SOLs? Similarly, what purpose would TOP-002, R1 serve? We suggest the SDT to first establish a principle regarding the need to operate within SOLs, then consider the implication of removing such a requirement from TOP-004-2, R1, when assessing other related requirements such as reporting exceedance (TOP-001, R5), performing day ahead assessment (TOP-002, R1), and developing methodology to calculate SOLs (FAC-014), etc. Finally, if the industry wishes to reduce the potential number of reports, such as those instances in which the SOLs are temporarily exceeded (popping in and out), a time and/or a percentage of SOL threshold may be introduced to achieve this.
Response: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has added TOP-001-1, Requirement R6 and modified TOP-001-1 Requirement R7 to require a subset of SOLs to be reported to the RC. **TOP-001-2, R6**. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability. **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded. The SDT does not plan to reintroduce a requirement to operate within all SOLs. The SDT believes that the true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue. Further, no other commenters have expressed this concern.		
Colmac Clarion	Yes	Assume this is System Operating Limit and Interconnect Reliability Operating Limit (need to cite for first time acronym use as was done with 'BES' in purpose statement). Unsure of exact setpoint of reporting, but would likely be at anytime load approaches or exceeds planned or immediately available generation; perhaps within 2-5% greater then parity.
Response: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has modified Requirement R7 to require a subset of SOLs to be reported to the RC. To satisfy the concerns expressed by the minority, the SDT will make that subset of SOLs include the any non-IROL SOLs that the RC identifies as required to be reported to it. The requirement will further specify that this communication may be accomplished through SCADA to reduce communication burdens. **TOP-001-2, R6**. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability. **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.		

Organization	Yes or No	Question 3 Comment
The drafting team added the full term, "System Operating Limits" as suggested.		
Ameren	Yes	
Response: Thank you for your response.		

4. TOP-004-3, R2: Regarding Agreements on switching – Based on comments received from the first posting, the SDT is considering deleting this requirement. TOP-001-3, Requirement R4 already requires coordination of operations. Given that requirement, is TOP-004-3, Requirement R2 still necessary? Do you agree that TOP-004-3, Requirement R2 can be deleted?

Summary Consideration: The requirements of Reliability Standards should specify "What" is to be done to ensure reliability. The SDT feels that operating agreements may be one example of "How" Reliability Entities work to coordinate operations, but does not feel Reliability Standards should restrict the industry participants with regard to the various methods that may be used to ensure coordination is effected. The majority of respondents agree with this position and that the requirement should be deleted. In the next posting, TOP-004-3, Requirement R2 will be deleted.

In addition, since there would only be one requirement left in TOP-004-3, Requirement R1 has been moved to TOP-001-2, Requirement R5.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	Operating Agreements cover activities other than switching. We believe the requirement should be retained but any duplication eliminated.
Response: The SDT agrees that agreements may cover activities other than switching. The requirements of Reliability Standards should specify "What" is to be done to ensure reliability. The SDT feels that operating agreements may be one example of "How" Reliability Entities work to coordinate operations, but does not feel Reliability Standards should restrict the industry participants with regard to the various methods that may be used to ensure coordination is effected.		
IRC Standards Review Committee	No	(Note that CAISO abstained from the following comments)No, this requirement should not be deleted. Agreements among TOPs are needed to ensure proper coordination of operational plans and actions. However, we do not agree that "switching of synchronous tie lines" should be specified in the requirement, nor should it be the only action specified in a TOP agreement as there are other items such as coordinating reactive power and voltage support, planned and forced outages, emergency operation, restoration, re-synchronization, etc. that need to be included in the agreement. We suggest this requirement be revised to: "Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specifies operation coordination among them."
Response: The SDT believes you have hit upon precisely the concern it has. The proposed TOP-001-2, Requirement R4 requires coordination of operations with other Reliability Entities when operations are known or expected to have a reliability impact upon other Reliability Entities. The SDT recognizes that having an agreement in place specifying switching of synchronous BES tie lines, per the content of TOP-004-3, Requirement R2 is a subject that rightfully should be included with the coordination that is required by TOP-001-2, Requirement R4. Conversely, the full coordination of operations cannot be included within the more narrowly defined scope of coverage of TOP-004-3, Requirement R2. Further the SDT recognizes that the scope and number of individual agreements, which may be needed to ensure that all operations are fully coordinated for all operations known or expected to have a reliability impact upon other Reliability Entities is highly likely to vary greatly from region to region or organizational arrangement to organizational arrangement. Thus, the SDT does not feel it is appropriate, nor even feasible, to try to list in the Reliability Standards all the individual types of agreements which may be required. "What" is needed is a requirement that all Reliability Entities properly		

Organization	Yes or No	Question 4 Comment
and adequately coordinate operations with other reliability entities. Having agreements of various types may be one example of "How" that coordination is put into place.		
WECC	No	We believe there is a need for clear agreements
Ameren	No	Agreements (formal or informal) are necessary to describe the conditions under which the coordinated switching in TOP-001 takes place. It will be impossible for Transmission Planners to properly analyze the conditions that can be expected if there are no "rules" for operation.
Brazos Electric Power Cooperative, Inc.	No	Either leave TOP-004-3, R2 as is or move a requirement for an Agreement into TOP-001-3, R4.
Response: The SDT cannot disagree that agreements may be appropriate, depending upon the relevant regional requirements and organizational arrangements. However, the SDT believes that "What" is required is coordination of operations. The SDT further believes that agreements may be an example of "How" coordination is accomplished, but not necessarily the only way.		
New York Independent System Operator	No	No, this requirement should not be deleted. Agreements among TOPs are needed to ensure proper coordination of operational plans and actions. However, we do not agree that switching of synchronous tie lines should be specified in the requirement, nor should it be the only action specified in a TOP agreement as there are other items such as coordinating reactive power and voltage support, planned and forced outages, emergency operation, restoration, re-synchronization, etc. that need to be included in the agreement. We suggest this requirement be revised to: Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specifies operation coordination among them.
Response: The SDT agrees with you that switching should not be the only action specified for agreement. The SDT cannot disagree that agreements may be appropriate, depending upon the relevant regional requirements and organizational arrangements. However, the SDT believes that "What" is required is coordination of operations. The SDT further believes that agreements may be an example of "How" coordination is accomplished, but not necessarily the only way. The SDT does not believe it is possible to list all the possible ways of "How" a requirement may be met.		
Independent Electricity System Operator	No	We agree that specificity language such as specify switching of synchronous BES tie lines does not need to be included in R2. However, Operating Agreements cover activities other than switching, such as emergency assistance, switching coordination and communication, voltage/VAR support, system restoration, synchronization, etc. We suggest keeping R2, revising it to eliminate any duplication with other requirements and defining the minimum elements that should be included in the agreement.
Response: The SDT agrees with you that switching should not be the only action specified for agreement. The SDT cannot disagree that agreements may be		

Organization	Yes or No	Question 4 Comment
appropriate, depending upon the relevant regional requirements and organizational arrangements. However, the SDT believes that "What" is required is coordination of operations. The SDT further believes that agreements may be an example of "How" coordination is accomplished, but not necessarily the only way. The SDT does not believe it is possible to list all the possible ways of "How" a requirement may be met. The SDT does not believe that an agreement necessarily equates to coordination, although, depending upon organizational arrangements and relationships, agreements may be an appropriate part of "How" coordination is effected.		
American Transmission Company	No	Again, TOP-001-3 requires general coordination vs. TOP-004-3 has a very specific requirement regarding agreements that specify switching of synchronous BES tie lines. The two requirements are different in scope and are, therefore, not redundant.
Response: The SDT agrees that an agreement and coordination differ in scope. Whereas coordination is "What" is required to ensure reliability, an agreement may be part of "How" coordination is effected.		
SERC OC Standards Review Group	Yes	If the SDT agrees with deleting R2, we suggest that R1 should be included in TOP-002 and TOP-004-3 retired.
FirstEnergy Corp	Yes	Yes, we agree with the recommendation to delete TOP-004-4 R2. Since this change would leave only one requirement within the TOP-004-4 standard, we urge the team to consider incorporating the requirement into another standard. One suggestion is consider adding the requirement to standard IRO-005-3 titled "Reliability Coordination - Current Day Operations". This could be added as a new requirement of IRO-005-3 or possibly a sub-requirement of requirement R11 of the IRO-005-3 standard. Alternatively, the requirement could be placed into the TOP-001 standard.
Response: The SDT agrees and has moved TOP-004-3, R1 to TOP-001-2, R5.		
FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool	Yes	If the requirement is deleted, you might want to consider changing the time frame to include the Planning Horizon to clarify that operating procedures / agreements between utilities are required in the long term (e.g., interconnection agreements, etc.), as well as to align with FAC-002 and the TPL standards
Response: Since switching of synchronous BES tie lines is an operations activity that may be included in the higher level "operations known or expected to have a reliability impact on other reliability entities", the SDT believes that the proposed Time Horizons proposed are appropriate. The Planning Horizon is applicable to activities more than one year in the future, and, therefore switching activities are not expected to have a reliability impact upon other entities in that Time Horizon. No change made.		
Exelon	Yes	Is there a typo in the question? TOP-001 does not have a rev 3. Assuming the intent is to refer to TOP-001-2,

Organization	Yes or No	Question 4 Comment
		R4 we agree.
American Electric Power	Yes	Please note the typographical error in question 4. TOP-001-3 in question 4 should read TPO-001-2.
Response: You are correct – the reference should have been TOP-001-2.		
Dominion Resources Inc.	Yes	It is not clear what an agreement between TOPs to “specify switching” of tie lines is supposed to be. If it is supposed to be an interconnection agreement, those are usually between Transmission Owners. Requirement R2 can be deleted.
Xcel Energy	Yes	We agree R2 is not necessary and should be deleted. Additionally, the use of the term "Agreements" is concerning, especially when the additional language requires one to "specify switching".
Midwest ISO Stakeholders Standards Collaborators	Yes	
MRO NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	
Southern Company	Yes	Redundant requirements in separate standards are both confusing and waste resources.
NextEra Energy Resources, LLC	Yes	
Colmac Clarion	Yes	
E.ON U.S.	Yes	
Con Edison System Ops	Yes	It should be deleted. I see no need for keeping the R2 wording in there. It's confusing and leaves too much up to interpretation. As stated above, the "coordination of operations" wording in R4 would suffice.
Manitoba Hydro	Yes	
Entergy Services	Yes	

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	
ISO New England Inc.	Yes	We beleive this is sufficiently covered by the Standards in their totality.
Puget Sound Energy	Yes	
ITC Transmission	Yes	
Bonneville Power Administration	Yes	
PJM's NERC and Regional Coordination Department	Yes	PJM agrees that there is no need to include a requirement that focuses on switching procedures.
Response: The SDT thanks you for your support.		

5. The RTO SDT is attempting to respond to a directive in FERC Order 693 where a specific country-wide advance notice time period for planned outage notification would be established. Prior to writing such a requirement, the RTO SDT is polling the industry to see if it is needed and what the time period would be. Please indicate if you agree with such a provision. If you agree then please provide a number of days that you would consider appropriate for such advance notice, e.g., 7 days. If you disagree, then please state specific reasons for your disagreement.

Summary Consideration: Order 693, paragraph 1621 stated: “We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.” The SDT posed this question as a fact finding exercise in order to assist them in making a decision on how to respond to the FERC directive. In that regard, the SDT thanks all those who took the time and effort to explain their reasoning as part of their comments. The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions.

After reviewing the industry comments, the SDT concluded that TOP-001-1, Requirement R4 adequately covers this issue. The SDT bases this position on the requirement which includes the Operations Planning Time Horizon that covers the period from one day to one year. The requirement mandates that all plans are coordinated. The SDT interprets this to include planned outages when they are known.

Therefore, the SDT will not be drafting an additional requirement for a national standard advance notice time period for planned outage notification.

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
PJM's NERC and Regional Coordination Department	No	A mandated common time-period would likely conflict with some already FERC-approved procedures. Moreover, a common timing requirement will likely as reduce the benefits and flexibility of some procedures, as it would provide benefits to others.
Consumers Energy Company	No	Communication of planned or scheduled outages should take place in the planning phase. Communication should be as early in the phase as possible for all TOs GOs and BAs effected by the outage. To have a nationwide standard is too confining and removes possible flexibility that can come from open communication. TOP-003-0 requires communication of outage information on a daily basis.
SERC OC Standards Review Group	No	A time limit does not need to be established. Entities need to be able to plan short term outages, both transmission and generation when conditions permit in order to minimize impacts to the reliability of the system. For example, a transmission line in need of maintenance might only be available upon the outage (forced or planned) on a particular generator. With a standard in place, this opportunity would be missed. Delaying maintenance on a transmission line puts it at a greater risk of a forced outage.

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
FirstEnergy Corp	No	We do not believe there is a reliability need to establish a common industry wide lead-time for planned BES facility outages. It should be left to the RC and the applicable entities that it monitors (TOPs, GOPs) to establish agreed upon outage coordination procedures. In fact, it should not be expected that a minimum lead-time must always be rigidly adhered to. Consider that many transmission lines can only be taken out of service during a generator outage. If generator unit experienced a forced outage that would permit certain transmission lines to be maintained, such maintenance should not be delayed to simply adhere to a specific lead-time requirement. The RC's and their monitored entities should be given the flexibility to develop a process that is suitable to meet their needs.
Dominion Resources Inc.	No	(including # of days if appropriate): We don't recommend a country-wide advance notice. However, we agree that it is within the purview of the Reliability Coordinators to reach agreement with the applicable entity and set outage reporting requirements to meet their reliability assessment needs without the development of a new NERC reliability standard.
Northeast Power Coordinating Council	No	While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region. Such notification requirements should be established within each region based on the needs of the RC.
Midwest ISO Stakeholders Standards Collaborators	No	We do not believe there is a reliability need to establish an industry wide advance notification procedure for transmission outages. We believe that the need for advance notification of transmission outages should be identified completely between the TOP and RC in their outage coordination procedures. In fact, we believe such a requirement could actually be a detriment to reliability. Consider that many transmission lines can only be taken out of service during a generator outage. If the generator were to trip, the transmission line could not be taken out of service for lack of sufficient advance notice delaying the maintenance of the line and, thus, increasing the potential for the line to be forced out. It is not clear what reliability benefit could even be achieved by having an industry wide advance notification requirement. We believe that should such a requirement become a reality, there will be further reliability detriment as TO/TOPs delay maintenance in a struggle to transition to comply with such a requirement.
MRO NERC Standards Review Subcommittee	No	After the review of the paragraph 1612 of the FERC final order 693, the MRO NSRS would like them to be more specific about the type of outages and consistent with the Reliability Coordinator's requirement; the Reliability Coordinator has a wide-area view. How would this country-wide advance notice improve reliability for two independent systems not physically interconnected?
IRC Standards Review Committee	No	This should be handled on a local or regional basis. There is a wide diversity of systems in place with reporting requirements defined, in some cases based in market requirements. It may not be reasonable to place the least common requirement on all entities in NERC.
Southern Compnay	No	No time limit needs to be established. Entities need to be able to plan short term outages, generation and transmission.

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
		The Eastern Interconnection presently has an advanced outage notification through the NERC SDX.
American Electric Power	No	The current rules for each region are followed today and coordination is done very well. Seams agreements address the coordination across regions. Therefore, a country-wide period is not necessary from a reliability perspective. If it is otherwise determined to be necessary, AEP believes that it should be done at the IROL level since, by definition, these are the situations with wide area impact.
E.ON U.S.	No	The RCs already have advance notification requirements which TOPs must follow. Most BES facilities have limited impact on neighboring systems. Depending on the level of notification, this could impose an undue burden on Transmisson Operators and field switching personnel in performing needed maintenance. The Regions should identify a subset of facilities (similar to the ECAR Facility Outage Notification Table) subject to advanced notification requirements. Should a country-wide advance notice time period be established it should only apply to 200kV and above.
Oncor Electric Delivery	No	Comments (including # of days if appropriate): Oncor Electric Delivery does not believe a country-wide notification period is necessary. As each interconnection has it's unique characteristics, there is no assurance that a common advance notification period would work for all. Additionally, setting a common date within a NERC standard seems inconsistent with the intent of reliability based standards. Advanced notification seems to be more of a market function and is not reliability based.
Manitoba Hydro	No	We do not believe there is a reliability need to establish an industry wide advance notification procedure for transmission outages. We believe that the need for advance notification of transmission outages should be identified completely between the TOP and RC in their outage coordination procedures.
Entergy Services	No	There are processes already in place to ensure that outages are coordinated between affected systems. Creating a nation-wide requirement to set an advance notice time is not in the best interests of reliability. Rather flexibility should be allowed to coordinate and agree upon required maintenance activities that are necessary to ensure continued reliability.
Duke Energy	No	This comment form is not the right place to address this issue. We would have significant concerns with the idea too much to support a requirement that hasn't been drafted yet. Existing processes are in place between neighboring entities to exchange this type of information.
Ameren	No	First, the definition of planned outage is anything but an industry standard. So the rules around timing are putting the cart before the horse, And, anything in days is not practical given the need to get to short-term planned maintenance and the impacts of weather and forced outages on these planned outages. If a notification time is absolutely deemed necessary, 30 minutes to 1 hour would be workable under a mandatory, enforceable NERC standard framework.

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
Brazos Electric Power Cooperative, Inc.	No	At this time I see no reliability benefit for this requirement.
New York Independent System Operator	No	This should be handled on a local or regional basis. There is a wide diversity of systems in place with reporting requirements defined, in some cases based in market requirements. It may not be reasonable to place the least common requirement on all entities in NERC.
ISO New England Inc.	No	While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region and, as such, notification requirements should be established within each region based on the needs of the RC. These may be dictated by an entities market structure, which should not be influenced by NERC Standards.
CenterPoint Energy	No	CenterPoint Energy does not see a reliability-related need to establish a continent-wide requirement that specifies the time frames for advance notification of planned outages. Such an approach does not appear practical considering the varying types of outages (circuit breakers, transformers, buses, and lines) and differing long-range and short-range scheduling time frames. As regional practices are already in place, CenterPoint Energy recommends outage scheduling time frames continue to be determined on a regional basis.
Con Edison System Ops		Unless the piece of equipment is in a direct neighboring system, what utility would this offer to a TO? "Operations are already coordinated" amongst neighboring TO's with regard to tie-lines. It would not offer much in the way of information on how we operate our system.However, ConEd already sends notification of all of its approved outages on the Bulk Electric System to the NYISO via email automatically. So, I dont think it would be difficult to do if someone decides that they want 7 or 10 day notifiation on something. If this requirement came into being, the NYISO could then disburse COnEd's outage info to NPCC and rest of the East.A hard-line 7 or 10 day rule will be tough to enforce though. Many outages get approved much closer to the actual date...many within 2 days of the start.
ITC Transmission		We would rather see a requirement that the RC specify the time period requirements for planned outages. While not opposed to having a uniform time requirement, we are not sure if it is necessary. If a time period is to be developed, it should consider voltage level, in other words more lead time for higher voltages. In addition, RC specified planned outage time period requirements should apply to transmission and generation outages.
WECC	Yes	We believe outage notification to the RC for all equipment 100kV and above, and all generator outges of 50MW and above should be a mininum of 96 hours notice in advance.
FMPA and its All Requirements Project Participants, as follows:	Yes	We believe that such a provision is necessary to enable coordination of major maintenance outages to ensure resource adequacy for the region for generation related outages, and to ensure coordination of scheduled transmission outages in a localized area, for seasonal assessment purposes. There are probably two types of maintenance to be addressed,

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool		major maintenance schedules, and more minor maintenance due to equipment failure that does not cause an unscheduled outage. First, each region does seasonal assessments, it may be a good idea to tie major maintenance schedules as input into the region's seasonal assessments, but allow flexibility in the actual schedules of these major maintenance schedules, with a reasonable input time frame to provide that input, e.g., two months before the start of the season. Second, there will always be unexpected maintenance schedules of shorter duration due to equipment failure that does not cause the facility to have an unscheduled outage, but, needs to be corrected. These are much more difficult to coordinate and schedule and may not allow a multi-day advance notice, so, maybe we could make the requirement only apply to major maintenance schedules.
Exelon	Yes	Follow existing Guidelines, GADS states "well in advance" as notification for "Planned" outages. This typically means more than 30 days in advance. PJM uses the 30 day definition for "Planned". Nuclear / INPO uses 28 days (4 weeks) from an INPO definition for "Planned". 30 days seems to be a reasonable requirement.
Colmac Clarion	Yes	Current policy under some existing contract operators requires initial notification on a rolling 3 year plan and additional notification to 'dispatcher' at 30 days. Generally, verbal notification is also conducted between generating facilities and Transmission operator on a much shorter and timely basis additionally. Transmission/Distribution company has a similar long range, and short notification cycle.
Independent Electricity System Operator	Yes	While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region. Such notification requirements should be established within each region based on the needs of the RC. Our experience in handling short and long term planned outages informs us that the timing and duration of outages will determine the allocation of time and other resource to assess impacts of the outages on the system. For short duration outages, a short term assessment is usually adequate as system conditions and topology are more predictable. The longer the duration of a planned outage, the less predictable are the system conditions and the more likely that other transmission facilities will be out of service during that period.
PacifiCorp	Yes	The appropriate number of days should be established on a region-wide basis, not a country wide basis. Each region has unique infrastructure that requires specific advance notice.
Bonneville Power Administration	Yes	No preference.
NextEra Energy Resources, LLC		No comment.
Xcel Energy	Yes	

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
Response: Thank you for your response. Please see the summary response for details.		

6. Do you generally support the revised standards? If your response is 'No', please explain your single biggest concern with the revised standards, including which specific requirement or set of requirements causes you the most concern and why.

Summary Consideration: Due to industry comments the SDT changed the following:

TOP-001-2, R2. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions.

TOP-001-2, R4. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected by the Transmission Operator to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. Such operations include, but are not limited to, relay or equipment failures and changes in generation, Transmission, Load, or operating conditions.

TOP-001-2, R6. Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs) which, while not IROLs, support its local area reliability.

TOP-001-2, R7.Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.

TOP-001-2, R2 VSL	The Transmission Operator did not inform one affected Transmission Operator of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform two affected Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform three affected Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or anticipated Emergency conditions. OR The Transmission Operator did not inform four or more affected Transmission Operators of actual Emergency and anticipated Emergency conditions.

TOP-001-2, R6 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL which, while not an IROL, supports its local area reliability.	The Transmission Operator did not inform its Reliability Coordinator of two SOLs which, while not IROLs, supports its local area reliability.	The Transmission Operator did not inform its Reliability Coordinator of three SOLs which, while not IROLs, supports its local area reliability.	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs which, while not IROLs, supports its local area reliability.

TOP-002-3, R1.Each Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential single Contingency events.

TOP-002-3, M1.Each Transmission Operator shall have evidence of an assessment for next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

TOP-002-3, R1 VSL	N/A	N/A	N/A	The Transmission Operator does not have an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and potential single Contingency event conditions.

TOP-003-1, R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include:

TOP-003-1, Part 1.1, bullet #1: Long term outages of Bulk Electric System equipment, as specified by the Transmission Operator or Balancing Authority,

TOP-003-1, R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. .

TOP-003-1, R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities , the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments.

TOP-003-1, M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data that have been unfilled.

TOP-003-1, M5.Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

TOP-003-1, R4 VSL	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R2 or R3 did not satisfy the obligations of the documented specifications for data

Organization	Yes or No	Question 6 Comment
Real Time Best Practices Standards Study Group	No	The Real-time Best Practices Standards Study Group (RTBPSSG) feels that the deletion of TOP-004-2, R4 (Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes) does not provide an adequate level of reliability for the operation of the Bulk Electric System (BES) and the reasoning provided for the removal is flawed. The RTBPSSG believes that this is an important consideration for operations that should not be deleted and that with more deliberations an acceptable measure for such a requirement can be developed. The concept of operating in a known state has long been a fundamental concept of reliable system operations and if this requirement is deleted then there is no requirement to cover this concept. The idea of operating to preclude IROLs or to return to within the limit in Tv does not adequately address this concern.
Response: Returning below IROLs within T_v is the same as returning from an unknown state within 30 minutes on a practical basis. T_v can be shorter than 30 minutes and thus promotes a more reliable condition. Without specific suggestions as to how to measure the deleted requirement, the SDT is unable to respond other than to maintain the current position. No action taken.		
American Transmission Company	No	We support the revised Standards. However, the questions asked do not reflect the current redlined versions of the Standards. We should be commenting on the version of the Standard that the drafting team wants to move forward with. The comment form and questions should match the current redlined version and not ask questions related to a proposed changed version.
Response: Without specific indications of where you feel errors were made, the SDT is unable to respond.		
Northeast Power Coordinating Council	No	1. We disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time."SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability?Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other 2. TOP-002-3 M1--Power flow study results will not be available for those days where studies are not required. Those days may be considered pre-studied or a normal studied state. How is this to be measured?

Organization	Yes or No	Question 6 Comment
		3. TOP-002-3 R2, R3 ? A plan should be required when the review warrants it and should include both IROL and SOL. In a normal state there may already be existing coordination between reliability entities with no need to re-communicate. 4. TOP-003-1R1: Reference to the Functional Model in the requirement may not be appropriate. This requirement may be clearer if the specific responsibilities are included. R1.1 Long Term Outages should be defined or clarified. 5. What about other outages that are potentially impactive? 6. In general, it is not clear that the data specification includes real time communications or operational planning requirements. 7. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some voice recorders are designed to retain data for 90 days. Have data recordings stored longer than 90 days only if requested by the RC or TOP.
ISO New England Inc.	No	1. We disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time."SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability? Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? 2. TOP-002-3 M1--Power flow study results will not be available for those days where studies are not required. Those days may be considered pre-studied or a normal studied state. How is this to be measured? 3. TOP-002-3 R2, R3 A plan should be required when the review warrants it and should include both IROL and SOL. In a normal state there may already be existing coordination between reliability entities with no need to re-communicate. 4. TOP-003-1R1: Reference to the Functional Model in the requirement may not be appropriate. This requirement may be clearer if the specific responsibilities are included. 5. R1.1 Long Term Outages should be defined or clarified. What about other outages that are potentially

Organization	Yes or No	Question 6 Comment
		impactive? 6. In general, it is not clear that the data specification includes real time communications or operational planning requirements. 7. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some voice recorders are designed to retain data for 90 days. Have data recordings stored longer than 90 days only if requested by the RC or TOP.
Response: 1 – Based on the previous comments received on this issue, the industry agrees with the SDT position of deleting this phrase. You have not presented any justification or additional evidence that would cause the SDT to reverse its decision. No, the SDT does not believe the two standards contradict each other. 2 – Neither the measure nor the requirement states that you must have a power flow study for each day. The measure states that you COULD have a power flow study as one method of measuring compliance. 3 - As drafted it is required to have a plan to mitigate IROL as identified by the next day assessment. Mitigation plans are not required for “normal” states. The SDT addressed the SOL issue in point #1. 4 –The SDT agrees and has deleted the reference to the Functional Model. The timeframe indicated here is Operations Planning which incorporates one day to one year. This should be sufficient to ‘define’ long term. No action taken for this comment. **TOP-003-1, R1**. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include: 5 – The statement includes the term ‘but not limited to’ so it does not preclude the inclusion of other information. No action taken. 6 – This is a specification and not the actual transfer of data so the Time Horizon is Operations Planning. No change made. 7 – The SDT has modified Measures 4 & 5 as a result of researching your comment. The SDT has changed data retention for Requirements 4 & 5 to 90 days. **TOP-003-1, M4**. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data that have been unfilled. **TOP-003-1, M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.		
Midwest ISO Stakeholders Standards Collaborators	No	1. We believe removing the requirements for SOLs in this standard will make it unacceptable to FERC. Thus, the drafting team will have to start over when FERC remands the standard.

Organization	Yes or No	Question 6 Comment
		2. The VSLs for TOP-001-2 R2 are based on the number of times the TOP did not inform the RC of Emergency conditions. Over what time period does this apply? In perpetuity? From last compliance audit? 3. We believe the VSLs for TOP-001-2 R6 violates the Commission's guideline 4 established in their VSL order. The VSLs are based on the number times the TOP did not act to mitigate the magnitude and duration of an IROL exceedance within its Tv. However, the associated requirement states The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv. Note that the requirement talks about an IROL in the singular. Thus, failure to act on one occasion is a single violation. Failure to act on two occasions is two separate violations not a higher VSL. We suggest that a binary Severe VSL be selected or that you modify the requirement to consider IROLs in the plural. 4. In TOP-002-3, the drafting team should consider making R2 a sub-requirement of R1. Isn't it a sub-component of the assessment the TOP must have in R1? 5. R3 should be made sub-requirement of R2. 6. M1 deviates from R1 in that M1 says that the TOP shall have evidence that it performed an assessment while R1 says it shall have an assessment. Likewise, the VSL differs from the requirement in the same way and should be made to match the requirement. 7. In TOP-003-1, we note that R3 requires the BA to distribute its data specification but there is not a similar requirement to have a data specification like R1 for the TOP. 8. We believe R3 belongs in the BAL standards. 9. We also suggest that the VSLs for R4 and R5 could be graded to include multiple levels. In R4, we believe the additional VSLs could be defined based on the percentage of data that is not supplied. The VSLs for R5 could be graded based on the number TOPs and BAs that the TOP did not supply data and information to. We further believe that the portion of the requirement in R5 that applies to the BA should be moved to the BAL standards. 10. In TOP-004-3, M1 appears to be a measure of non-compliance with R1. Aren't measures supposed to identify how compliance is measured not non-compliance? The VSLs measure non-compliance.
Response: 1 – Based on the previous comments received on this issue, the industry agrees with the SDT position. You have not presented any justification or additional evidence that would cause the SDT to reverse its decision. 2 – The SDT has revised the VSL.		

Organization	Yes or No	Question 6 Comment		
TOP-001-2, R2 VSL	The Transmission Operator did not inform one other Transmission Operator of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform two other Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform three other Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or anticipated Emergency conditions. OR The Transmission Operator did not inform four or more other Transmission Operators of an actual Emergency or anticipated Emergency conditions.
3 – The SDT agrees with the suggested change to the VSL.				
TOP-001-2, R6 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL which, while not an IROL, support its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs which, while not IROLs, support its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs which, while not IROLs, support its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs which, while not IROLs, support its local area reliability**.**
4 & 5 – The SDT believes these are separate standalone requirements. No change made. 6 – The SDT has changed M1 and the R1 VSL. **TOP-002-3, M1**. Each Transmission Operator shall have evidence of an assessment for next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.				
TOP-002-3, R1 VSL	N/A	N/A	N/A	The Transmission Operator does not have an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and potential single Contingency

Organization	Yes or No	Question 6 Comment

				event conditions.

7 – Please see R2 of TOP-003-1.

8 – The SDT does not believe that there is a relevant spot in the BAL standards for such a requirement. No change made.

9 – The SDT has reworded Requirement R4, M4, and the wording of the Severe VSL to accommodate your concerns. The SDT does not feel that with this new wording any change is required to add levels of VSL. The SDT reviewed the R5 VSL and feels that it is correct and has not made a change in this area.

TOP-003-1, R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. .

TOP-003-1, M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data that have been unfilled.

TOP-003-1, R4 VSL	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R2 or R3 did not satisfy the obligations of the documented specifications for data. .

10 – The SDT felt it would be easier to provide information if and when an IROL and IROL T_V was violated compared to providing information of every operating hour proving that an IROL and IROL T_V was not violated. No change made.

Organization	Yes or No	Question 6 Comment
FirstEnergy Corp	No	1. The drafting team's response to FE's fifth comment in the Draft 1 Question 12 is not sufficient for us to understand their thought process on the matter. Our prior comment raised a concern with the removal of TOP-007-0 R3 that states, "A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load ?? The SDT responded that this matter is covered in EOP-001-0, Requirement R3.3 that states, R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.? 2. The SDT is proposing to retire PER-001 and FE believes the PER-001 requirement R1 and its associated measure M1.4 should be re-enforced within the TOP standards. This operator authority was a focal point of recent readiness evaluations within the industry and should be explicit within a TOP

Organization	Yes or No	Question 6 Comment
		requirement. We would appreciate further explanation from the SDT if they feel the change is still not required. 3. FE disagrees with the SDT's response to our comment on Draft 1 Q4 which questioned which contingencies are required to be evaluated within the operating horizon. The prior TOP-002-2 requirement R6 stated R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements. This concept is lost in the newly proposed TOP standards. In responding the SDT stated that the Transmission Operator is not limited to single Contingencies or bus faults but must study any and all conditions that may result in exceeding any of its System Operating Limits during anticipated normal conditions as stated in the Requirement. The potential Contingencies to be studied are limited to those spelled out in the TPL standard. FirstEnergy does not agree that there is an expectation to cover all TPL contingencies within the operating horizon. As vetted by industry in the recent proposed and subsequently withdrawn SAR that proposed to evaluate credible multiple contingencies? it is clear that studies within the planning and operations horizon are distinctly different and that there is no expectation to cover events in real-time or within the operating horizon (next day, next month, through one year out) beyond single contingency. We ask the SDT to clarify their comment in this regard. 4. We would like the SDT to explain why it found the need to introduce the term each in requirement R1 of TOP-002-1. As re-worded, the focus of the compliance audit may become too structured on strict adherence to each directive rather than the TOP meeting the intent of the RC's directives. If the wording remains, we believe the VSLs can be better graded and that missing a single directive should not warrant a severe VSL. Many of the proposed VSLs use a quartile approach (0-25%, 25-50%,50%-75% and >75%) of gauging if some reliability action was missed. FERC in its VSL Order dated June 19, 2008 took exception to the quartile approach and felt it violates its Guideline 1 ?Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance? see paragraphs 19 through 21. The VSL DT revised the VLS that previously used a quartile score to reflect a 0-5%, 5%-10%, 10-15% and >15% graded VSL approach. Its suggested that the SDT reconsider its use of quartile VSLs. 5. We believe the VSLs for TOP-001-2 R6 violates the Commission's Guideline 4 established in their VSL order. The VSLs are based on the number times the TOP did not act to mitigate the magnitude and duration of an IROL exceedance within its Tv. However, the associated requirement states The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv. Note that the requirement talks about an IROL in the singular. Thus, failure to act on one occasion is a single violation. Failure to act on two occasions is two separate violations not a higher VSL. We suggest that a binary Severe VSL be selected or that you modify the

Organization	Yes or No	Question 6 Comment
		requirement to consider IROLs in the plural. 6. In TOP-003-1 R1.1 second bullet the SDT introduced a new requirement that for data exchange related to equipment at voltage levels below the BES and left the need for this data at the discretion of the TOP or BA. FirstEnergy believes the inclusion of equipment lower than normal BES levels should not be introduced on an ad-hoc standard by standard basis. Rather, if such equipment is deemed necessary for the reliability of the BES then the Facilities may need to be subject to other reliability standards such as vegetation management, preventative maintenance, etc. Inclusion of such equipment should be a registration issue handled through the Regional Entity and not within individual standard requirements. However, providing such data could be requested and provided on a voluntary basis, but if the equipment is deemed essential for BES reliability other standards likely apply.

Response: 1 – The SDT apologizes for any confusion. The duplicative standard is EOP-001-0, Requirement R2.3.

2 – The SDT deleted this requirement for numerous reasons. First, it is not measurable. Second, the standards themselves, once approved by FERC, not only grant but demand operating personnel implement real-time actions to ensure stable and reliable operations of the BES. No change made.

3 – The SDT has reviewed its response provided to the comments from First Energy for Q4 in Draft 1 and agrees that it was incorrect. The SDT added the word 'single' to TOP-002-3, Requirement R1 to clarify its position which is based on the development of the new TPL-001-1 standard.

> **TOP-002-3, R1**. The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential single Contingency events.

4 – The SDT believes that you meant TOP-001-2, Requirement R1. The SDT believes that if an entity misses a reliability directive, it is a Severe violation. No change made.

5 – The SDT agrees with the suggested change to the VSL.

TOP-001-2, R6 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL which, while not an IROL, supports its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs which, while not IROLs, supports its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs which, while not IROLs, supports its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs which, while not IROLs, supports its local area reliability**.**

6 – The SDT did not introduce a new requirement but was responding to a directive in Order 693, paragraph 1626 when this bullet was crafted. The SDT believes that if this data is required for planned outages then it is also important enough to be required in general. No change made.

IRC Standards Review	No	(1) We believe there is a fundamental principle that TOPs need to operate their systems within SOLs. We propose the SDT re-instate the deleted words from TOP-004 R1 that address SOLs. Recognizing that not

Organization	Yes or No	Question 6 Comment
Committee		all SOLs have an impact on interconnected system reliability if their exceedances are not mitigated within some target time period, we propose the SDT consider qualifying the SOLs which the TOP must operate within along the same line as we propose in our comments under Q2, namely, the set to be identified by the TOP subject to its RC's concurrence.(Please note that ERCOT abstained from these comments) To more fully address the issue with some SOLs that do not have any reliability impacts, we propose the SDT consider revising the definition of SOL. This will eliminate the need for each TOP to identify this subset and obtain the RC's concurrence. (2) We generally support the direction the SDT is moving but would require consideration of the comments provided in this transmittal.What is replacing TOP-001 R7? The requirement was previously TOP-008-R2, got moved to TOP-001 R7, but now both TOP-001 R7 is deleted and TOP-008 is deleted. Is there still going to be a requirement to use the most restrictive limit when multiple entities have different limits? (3) TOP-003-1 makes reference to functional responsibilities and responsibilities per the NERC Functional Model. We do not agree with these references since it is unclear the status of the NERC Functional Model and how it relates to the NERC Standards. It has been noted that the NERC Functional Model is only for guidance and is not a standard.
Response: 1 – Based on the previous comments received on this issue, the industry agrees with the SDT position of deleting this. You have not presented any justification or additional evidence that would cause the SDT to reverse its decision. For clarity, the SDT has added a new requirement to TOP-001-2 to cover the issue on SOLs that must be reported. **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. 2 – As pointed out in the responses to comments for the first posting, the SDT deleted this requirement as it is duplicative of IRO-05-3, Requirement R10. 3 – The SDT agrees and has changed the requirement accordingly. **TOP-003-1, R1**. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include:		
Exelon	No	In general, Exelon supports the revisions and appreciates the work being done by the SDT to consolidate and clarify the requirements. We have some concerns with the langauge in TOP-001-2 R4."Coordinate" - We believe this needs to be better defined. "Known or expected to have a reliability impact" – Reliability impact needs to be defined better, can measures be identified, such as; cause a system to violate a limit under expected conditions? Consider adding the words in the judgment of the TOP before the word expected. Otherwise this may become a point of contenetion and difficulty during an audit.If the GO is not removed (see question 2)the GO is not

Organization	Yes or No	Question 6 Comment
		likely to have the ability to know what reliability impacts its actions might have."other reliability entities" - needs to be defined. "Unless conditions do not permit such coordination" - if this clause is getting at the issue of time not available, consider unless based on the reasonable judgment of the TO, considering the facts and circumstances at the time, conditions do not permit such coordination.? We feel the point of the requiremnts should be when a GO/TO knows or reasonably should know that an action will have a substantial adverse reliability impact on another operating entity (define), the GO/TO should inform the other entity and consider that other entity's input in deciding how to operate, if time permits.
Response: The SDT believes that through analysis, reliability impacts on other reliability entities will be known and/or expected and this information should be shared to support reliability**.** No change made. The SDT does not see an industry consensus for removing the Generator Operator from this requirement. However, the Generation Operator will not know what causes an impact unless they have been told so by the Transmission Operator. Therefore, the SDT has added the suggested wording to the requirement. **TOP-001-2, R4**. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected by the Transmission Operator to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. Such operations include, but are not limited to, relay or equipment failures and changes in generation, Transmission, Load, or operating conditions. The SDT believes the requirement as drafted is sufficient. No change made.		
Consumers Energy Company	No	TOP-003-1 R1.1 needs to be more specific in identifying the equipment to be considered for inclusion.
Response: The SDT believes the individual entities are best capable of determining the data required to fulfill their reliability functions. No change made.		
Duke Energy	No	- TOP-001 R2 Need to change affected to adjacent, and in the VSLs.- TOP-001 R4 Change other to adjacent, - and in the VSLs.- TOP-001 R4 If coordinating means that we're posting the information on SDX, then we are in agreement.- - TOP-001 R6 Need clari
Response: Based on stakeholder comments, the SDT changed, "affected" to "other" in TOP-001, Requirement R2. 'Other' provides flexibility and includes "adjacent." The SDT believes that posting on SDX could be coordination but that the key element is that actions are coordinated in some manner. No change made.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>New York Independent System Operator</td><td>No</td><td>We generally support the direction the SDT is moving but would require consideration of the comments provided in this transmittal.What is replacing TOP-001 R7? The requirement was previously TOP-008-R2, got moved to TOP-001 R7, but now both TOP-001 R7 is deleted and TOP-008 is deleted. Is there still going to be a requirement to use the most restrictive limit when multiple entities have different limits?

TOP-003-1 makes reference to functional responsibilities and responsibilities per the NERC Functional Model. We do not agree with these references since it is unclear the status of the NERC Functional Model and how it relates to the NERC Standards. It has been noted that the NERC Functional Model is only for guidance and is not a standard.

The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some are designed to retain data for 90 days. The SDT should take into consideration the storage media. In some cases equipment is changed and the data may not be obtainable, or cost prohibited.</td></tr>
<tr><td colspan="3">Response: As pointed out in the responses to comments for the first posting, the SDT deleted this requirement as it is duplicative of IRO-05-3, Requirement R10.

The SDT agrees and has changed the requirement accordingly.

TOP-003-1, R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include:

The SDT has modified Measures 4 & 5 as a result of researching your comment. The SDT has changed the data retention for Requirements 4 & 5 to 90 days.

TOP-003-1, M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data that have been unfilled.

TOP-003-1, M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.</td></tr>
<tr><td>CenterPoint Energy</td><td>No</td><td>CenterPoint Energy believes reliability requirements should not include vague and unmeasurable, fill-in-the-blank provisions, like those shown in TOP-003 Requirement 1. R1 states Each Transmission Operator and Balancing Authority shall have a documented specification for data required to fulfill their respective responsibilities per the NERC Functional Model. In addition, CenterPoint Energy disagrees with the accompaning TOP-003 Requirement 4 that requires numerous entities to comply with fill-in-the-blank provisions developed through R1. As written, R1 leaves it open to the whim of a Transmission Operator or Balancing Authority to conjure a list of required data, without any process for impacted entities</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
		to argue the reasonabless of the data. In R1.1, the SDT has added two examples of required data by stating Long term outages of Bulk Electric System equipment when they are known and Equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority?. These vague examples leave it to the total discretion of a Transmission Operator or Balancing Authority. CenterPoint Energy recommends rewording Requirement 1 and deleting TOP-003 Requirement 4.
Response: The SDT has changed Requirements R1 and R4 to provide clarity to this issue. **TOP-003-1, R1**. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include: **TOP-003-1, R4**. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data.		
Independent Electricity System Operator	No	We do not support the revised standards. Our biggest concern is the removal of the requirement for TOP to operate within SOLs as stated in our response to Q#3. As stated in our previous comments we are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time."SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state, even before IROL violations become evident. If such upper bounds are to be ignored to enhance operating flexibility, the BES would be very vulnerable to instability, uncontrolled separation, or cascading outages upon the occurrence of subsequent contingencies. The 2003 blackout started off with an SOL violation, and is a good example of how a "localized" problem can propagate thru the interconnected network to become a widespread reliability problem.Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? We are also very concerned that R1/R2 in TOP-002 requires the TOP to assess potential exceedence of IROLs only but not SOLs. We feel strongly that R2 in TOP-002 should be revised so that it includes as part of the requirement, preclusion of operating in excess of any SOLs. Further, we believe that all SOLs should be respected in the planning time-frame and in real time with the exception of low likelihood or rare circumstances. WE believe the SDT may have misinterpreted our previous comments. By system voltage may be depressed? we were saying the voltage may be lower than normal, we did not explicit state or imply that the depressed voltage will cause a collapse which appeared was the basis of the SDT’s response that we

Organization	Yes or No	Question 6 Comment
		were talking about IROL - a subset of SOL. The argument that the TOP is required to calculate SOL but does not need to operate within all the time seems irrational. Operating with SOL all the time and correct exceedance within some defined time period is necessary to ensure reliability. The examples/rationale cited in the question asked in the previous comment form: The SDT felt that requiring a TOP to operate within all SOLs could effectively reduce the TOPs operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time. was but one such situation. Load shedding to reduce equipment loading is often regarded by TOPs as an exception, i.e., load is not shed to correct a temporary exceedance of equipment rating or a potential exceedance of applicable equipment rating if a contingency were to occur. The rationale is simply to not shed load if exceedance of the facility's continuous rating is expected to be temporary, or if a contingency were to occur then the expected loading will exceed the concerned equipment's applicable rating since we do not shed load pre-contingency to avoid shedding load after a contingency has occurred.Operating within an SOL w/o having to shed load under some circumstances is clearly conveyed in our comments (underlined in our comments above). However, without the fundamental requirement to operating within SOL, it opens the door to various kinds of unreliable operating conditions. A first overloaded line, which trips because it loading is not corrected, will cause loading on other lines to increase. There is no certainty as to when and where loading on the remaining system will cease to cause additional tripping. Also, the absence of such a requirement begs the question on the need to:(a) Calculate SOL (FAC-014) in the first place. The SDT's response that FAC-014 also requires the TOP to ?communicate your SOLs to other entities so that they can respect your operational limits? seems a bit unfair since the TOP, as the SOL developer, does not itself need to respect the SOL but others do. And who are these ?other entities? within the TOP area that need to respect the SOLs - The BA, GOP or the RC, while the TOP has the transmission reliability authority within its area and takes primary responsibility in transmission reliability (other than the RC who has a wide-area view and has the final authority)? (b) Perform day ahead analysis (TOP-002, R1) without requiring any follow-on actions if the analysis shows that SOLs will be exceeded. Developing SOLs and assessing if they will be exceeded would simply be an academic exercise. We are unable to determine how will not respecting SOLs and not having follow-on actions when SOLs are assessed to be exceeded contribute to reliability? (c) Report exceedances and corrective actions taken (TOP-001, R5). This serves no purpose if a TOP is not required to operate within SOLs. (2) TOP-002, R1 requires a TOP to assess next day operations and identify if any SOLs will be exceeded, and the actions related to SOL stops there. It is irresponsible for the TOP to not do anything such as adjusting outage plans and/or requesting adjustment to resource plans to arrive at operating conditions that will no cause SOLs to be exceeded. A requirement similar to that of R2 (for the IROL) should be developed. The only difference between them would be the need to prepare for load shedding when

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		mitigating measures run out. (3) We noted that some VSLs are graded according to the number of occurrences. Please refer to the recent posting on the revised VSLs for 8 sets of standards, in which the VSLSDT made reference to the June 2008 FERC Order on VSL. In the Order, FERC provided a guideline (among others) that VSLs should not be determined by the number of occurrence. Specifically, FERC's Guideline #4 stipulates that:Guideline 4 VSLs should be based on a single violation, not on a cumulative number of violations (unless stated otherwise in the requirement).We suggest the SDT to revise these VSLs accordingly.
Response: Based on the previous comments received on this issue, the industry agrees with the SDT position of deleting this requirement. You have not presented any justification or additional evidence that would cause the SDT to reverse its decision. The SDT has added TOP-001-2, Requirement R6 and modified TOP-001-2, Requirement R7 to provide clarity around this position. The SDT does not feel that the 2 standards contradict each other. **TOP-001-2, R6.** Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs) which, while not IROLs, support its local area reliability**.** **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded. TOP-002-3 is for planning purposes only. TOP-001-2 addresses operations. TOP-002-3, Requirement R1 explicitly requires the assessment of SOLs and Requirement R2 states that you should *plan* to avoid operating in excess of IROLs. You have not presented any evidence to convince the SDT to change our position and the majority of the industry agrees with the SDT's position. A change was made to TOP-001-2 to address operations as shown above. The SDT feels that TOP-002-3, Requirements R1 & R2 provides sufficient assurance that the next day operations will be reliable. The SDT does not agree with the contention that the revised standards will lead to unreliable operating conditions nor have you provided evidence of this contention. The SDT has not received consequential comments to cause the SDT to change its position. No change made. (b) The SDT feels that TOP-002-3, Requirements R1 & R2 provides sufficient assurance that the next day operations will be reliable. The SDT does not agree with the contention that the revised standards will lead to unreliable operating conditions nor have you provided evidence of this contention. The SDT has not received consequential comments to cause the SDT to change its position. No change made. (c) The SDT has modified TOP-001-2, Requirement R7 to provide clarity on what SOLs need to be reported. (2) The SDT feels that TOP-002-3, Requirements R1 & R2 provides sufficient assurance that the next day operations will be reliable. The SDT does not agree with the contention that the revised standards will lead to unreliable operating conditions nor have you provided evidence of this contention. The SDT has not received consequential comments to cause the SDT to change its position. No change made. (3) If the requirement is singular, then each occurrence is a separate violation. If the requirement is plural, then multiple occurrences are a single violation. The SDT believes this is consistent with the FERC Order on VSLs. Without specific references, the SDT sees no reason for change.		
Southern Compnay	No	TOP-001 R2: The phrase shall coordinate its respective operations known or expected to have a reliability

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		impact on other reliability entities could cause compliance issues due to the resulting subjectivity of the identification of other reliability entities. Recommend that it replaced with shall coordinate its respective operations known or expected to have a reliability impact on adjacent reliability entities?. It should be the responsibility of the adjacent reliability entity to further coordinate, if necessary, other appropriate reliability entities. The Measures and VSLs would need to be modified accordingly .TOP-002 R2 uses the word "plan" as a verb, and then it is referenced in R3 as a noun. This is propagated in the Measures and VSLs. Suggest the following wording change in R2: The Transmission Operator shall have a coordinated plan?? TOP-003 R1.1 - suggest that "Long term" be removed and replaced with "Planned". "Long term" could be interpreted to mean an outage that will not occur for quite some time (long lead time), or an outage that will occur sooner but will last for a long time. All outages should be communicated. R1.2 - Disagree with this requirement. We recommend that it be struck. The TO and the BA must be able to specify formats that can be utilized by their processes to ensure reliability.
Response: The word 'coordinate' is not used in TOP-001-2, Requirement R2 but upon review the SDT has modified the wording to address your concern about affected Transmission Operators. **TOP-001-2, R2.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions. The SDT sees no reason to change the wording in TOP-002-3, Requirements R2 & R3. Plan can be both a noun and a verb and the usage here is self-explanatory. Long term is 'defined' by the use of the Operations Planning Time Horizon which is limited to one year. The SDT believes that R1.2 is a reasonable attempt to solve the problem where there are 2 different systems involved. Deleting the requirement doesn't solve the problem. No change made.		
Brazos Electric Power Cooperative, Inc.	No	See responses to previous questions.
Response: Please see responses to previous comments.		
Bonneville Power Administration	Yes	Some suggestions:TOP-002-3 1) R1. Remove "and potential Contingency events". Any event could temporarily increase flows over the SOL (or IROL) or cause the SOL to decrease until the flows are mitigated per ROP-001. The system studies set the SOL's to protect the system for such events. The mitigation is then required in TOP-001-2 then (and TOP-004 if it is kept).

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		2) R1. Reword R1 similar to that of R2 in that TOP "plans" to preclude operating in excess of any SOLs for anticipated normal conditions. This is normal operational planning. All entities should not be planning to exceed SOL for normal conditions. Rewording: R1. "The Transmission Operator shall plan next days operation to preclude operating in excess of any System Operating Limits (SOLs) during anticipated normal conditions."
Response: The SDT believes that the phrase must remain as you must perform an assessment including Contingencies to properly analyze any exceedances of SOLs. The SDT feels that TOP-002-3, Requirements R1 & R2 provide sufficient assurance that the next day operations will be reliable. The SDT does not agree with the contention that the revised standards will lead to unreliable operating conditions nor have you provided evidence of this contention. The SDT has not received consequential comments to cause the SDT to change its position. No change made.		
Project 2007-02 Operating Personnel Comm Protocols SDT	Yes	The Operating Personnel Communication Protocols standard drafting team respectfully requests that the Real Time Operations team incorporate the following into your proposed TOP-001: ?Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have procedures for the communication of information concerning the transmission emergency alerts in accordance with the conditions described in Attachment 1 Transmission Emergency Alerts .? In addition, the Applicability Section 4 would need to include Reliability Coordinators. The Operating Personnel Communications Protocols Project 2007-02 was initiated to ensure that real time system operators use standardized communication protocols during normal and emergency operations to improve situational awareness and shorten response time. The SDT developed a new COM-003-1 Standard that has yet to be posted and is dependent upon revising at least two other standards (CIP-001 and appropriate TOP Standard). COM-003 contains requirements that specify:1. Use of three-part communication; 2. English language; 3. Common time zone; 4. NATO alpha-numeric alphabet; 5. Mutually agreed line identifiers; 6. The use of pre-defined system condition terminology such as those contained in the RCWG Alert Level Guide and EOP-002-2.This request is based on recent NERC Standards Committee direction to our team to incorporate the Reliability Coordinator Working Group's (RCWG) Alert Level Guide into a Standard. The consensus of our team is that a TOP Standard is the most appropriate location for the Transmission Emergency Alert language from the Guide as the energy emergency alert language is currently described in EOP-002-2. The RCWG Guide proposes the use of pre-defined system condition descriptions for use during emergencies for reliability related information. This guide was developed in response to a Blackout Report recommendation. Our team placed the energy cyber and physical security emergency alert language into CIP-001. Since the Real Time Operations SDT is currently modifying TOP-001 through 004, we seek your consent to incorporate the transmission emergency alert language to comply with the wishes of the Standards Committee.We believe that a TOP

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		Standard is the most appropriate location for this language for the following reasons:? The levels of emergency conditions related to the transmission system is based upon maintaining the transmission system within Interconnection Reliability Operating Limits. ? Your proposed TOP-001 R2 already requires the sharing of information of actual and anticipated transmission emergency conditions and the use of pre-defined terminology supports the efficient sharing of such information. The following text is appended here for the record. It is the OPCP SDT proposal for a revised TOP Standard that incorporates the TEA material.Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 1 of 17Effective Date: October 1, 2007A.Introduction1.Title: Transmission Operations2.Number: TOP-004-33.Purpose: To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies; and to communicate transmission emergency alerts.4.Applicability:4.1.Reliability Coordinator4.2.Balancing Authority4.3.Transmission Operators5.Proposed Effective Date: First day of first calendar quarter, one calendar year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter a year from the date of Board of Trustee adoption.B.RequirementsR1.Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).R2.Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.R3.Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.R4.If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.R5.Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.R6.Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:R6.1.Monitoring and controlling voltage levels and real and reactive power flows.R6.2.Switching transmission elements.R6.3.Planned outages of transmission elements.R6.4.Responding to IROL and SOL violations.R7.Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have procedures for the communication of information concerning the transmission emergency alerts in accordance with the conditions described in Attachment 1-TOP-004-3.C.MeasuresStandard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 2 of 17Effective Date: October 1, 2007M1.Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide

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		upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.M2.Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.M3.Each Reliability Coordinator, Balancing Authority, Transmission Operator shall have and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirement 7.Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 3 of 17Effective Date: October 1, 2007D.Compliance1.Compliance Monitoring Process1.1.Compliance Monitoring ResponsibilityRegional Reliability Organizations shall be responsible for compliance monitoring.1.2.Compliance Monitoring and Reset Time FrameOne or more of the following methods will be used to assess compliance:-Self-certification (Conducted annually with submission according to schedule.)-Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)-Periodic Audit (Conducted once every three years according to schedule.)-Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)The Performance-Reset Period shall be 12 months from the last finding of non-compliance.1.3.Data RetentionEach Transmission Operator shall keep 90 days of historical data for Measure 1.Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data1.4.Additional Compliance InformationNone.2.Levels of Non-Compliance:2.1.Level 1: Not applicable.2.2.Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.2.3..Level 3: Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.Standard TOP-004-3 Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 4 of 17Effective Date: October 1, 20072.4.Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:2.4.1Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.2.4.2Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.E.Regional DifferencesNone identified.Version HistoryVersionDateActionChange Tracking0April 1, 2005Effective DateNew0August 8, 2005Removed Proposed from Effective DateErrata1November 1, 2006Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November

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		1, 2006Revised2December 19, 2007Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)RevisedErrataStandard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 5 of 17Effective Date: October 1, 2007Attachment 1-TOP-004-3 Transmission Emergency Alert (TEA) LevelsIntroductionThis Attachment provides the procedures by which a Transmission Operator or Reliability Coordinator can advise of actions taken to manage potential or actual Interconnected Reliability Operating Limit (IROL) violations.All three operating alert states (EEAs, TEAs and SEAs) are independent of each other and should be declared independently but they may also be declared concurrently.A. General Requirements1. Initiation by Reliability Coordinator. A Transmission Emergency Alert (TEA) may be initiated only by a Reliability Coordinator at:1) the Reliability Coordinator's own request, or2) upon the request of a Transmission Operator1.1. Situations for initiating alert. A Transmission Emergency Alert may be initiated for the following reasons: When all the available generation resources (would also include dispatchable load facilities that dispatch similar to generators on an economic basis) have been committed to respect an IROL in the pre-contingency state or; When load curtailment procedures have been implemented to respect an IROL.2. Notification. A Reliability Coordinator who declares a Transmission Emergency Alert shall notify all Transmission Operators and Balancing Authorities in its Reliability Area. The Reliability Coordinator shall also notify Reliability Coordinators of the situation via theReliability Coordinator Information System (RCIS) using the System Emergency category. Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify all Transmission Operators and Balancing Authorities in its Reliability Area and Reliability Coordinators when the alert has ended.B. Transmission Emergency Alert LevelsIntroductionStandard TOP-004-3 Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 6 of 17Effective Date: October 1, 2007To ensure that all Reliability Coordinators clearly understand potential and actual actions taken to manage IROLs on the Interconnection, NERC has established three levels of Transmission Alerts. The Reliability Coordinators will use these terms when explaining actions taken to manage IROLs to each other. A Transmission Emergency Alert is an emergency communication protocol , not a daily operating practice, and is not an alternative to compliance with NERC reliability standards. The Reliability Coordinator may declare whatever alert level is appropriate, and need not proceed through the alerts sequentially.1. Transmission Emergency Alert 1 (TEA 1) ? All available generation resources committed to respecting IROLs.Circumstances: The Reliability Coordinator or Transmission Operator foresees or is experiencing conditions where all available generation resources are committed to respect the IROL and/or is concerned about its ability to respect the IROL.2. Transmission Emergency Alert 2 (TEA 2) Load management procedures in effect to respect IROLs.Circumstances: The Reliability Coordinator or Transmission Operator foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:?Public

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		appeals to reduce demand.?Voltage reduction. Interruption of non-firm end use loads in accordance with applicable contracts (for emergency purposes, not economic reasons) Demand-side management.Utility load conservation measures?TLR 6Note: TLR 5 would normally be implemented in advance of this alert state. Under some circumstances TLRs may not be available or effective and would not be called prior to this alert state.During TEA 2, Reliability Coordinators and Transmission Operators have the following responsibilities:2.1 Declaration period. The declaring Reliability Coordinator shall update the RCIS under System Emergency at a minimum of every hour until the TEA 2 is terminated.2.2 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may be contributing to the alert level. Where appropriate, the Reliability Coordinators shall inform the Transmission OperatorsStandard TOP-004-3 Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 7 of 17Effective Date: October 1, 2007under their purview of the pending Transmission Emergency Alert and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures and redispatching generation.The following additional actions should also be considered where appropriate: Notification of ATC adjustments. Resulting increases in ATCs shall be communicated to the market via posting on the appropriate OASIS websites by the Transmission Providers. Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the declaring Reliability Coordinator. Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the declaring entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators. Initiating inquiries on re-evaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of re-evaluating and revising SOLs or IROLs.2.3 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.2.4 Actions Prior to Declaration of TEA 3. Before declaring a TEA 3, all available generation resources must be committed. This includes but is not limited to: All available generation units are on-line. All generation capable of being on-line in the time frame of the emergency is on-line including quick-start and peaking units, regardless of cost. Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost. Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 8 of 17Effective Date: October 1, 2007?Operating Reserves. Operating reserves are being utilized such that the declaring entity may be carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.3.

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		Transmission Emergency Alert 3 (TEA 3) ? Firm load curtailment in effect to respect IROLs.Circumstances:The Reliability Coordinator or Transmission Operator foresees or has implemented firm load obligation interruption to respect an IROL.3.1 Continue actions from TEA 2. The Reliability Coordinators and the declaring entity shall continue to take all actions initiated during TEA 2.3.2 Declaration Period. The declaring Reliability Coordinator shall update the RCIS under ?System Emergency? at a minimum of every hour until the TEA 3 is terminated.3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities.3.4 Re-evaluating and revising SOLs and IROLs. The Reliability Coordinator of the declaring entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Re-evaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the declaring entity who has requested an TEA 3 condition. SOLs and IROLs shall only be revised as long as a TEA 3 condition exists or as allowed by the Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.3.5 Returning to pre-emergency SOLs and IROLs. Whenever the transmission systems can be returned to their pre-emergency SOLs or IROLs, the declaring Entity shall notify its respective Reliability Coordinator.3.5.1 Notification of other parties. When an alert has been downgraded, the Reliability Coordinator shall notify via the RCIS the affected Reliability Coordinators, Transmission Operators and Balancing Authorities that their systems can be returned to their normal limits.Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 9 of 17Effective Date: October 1, 20074. Transmission Emergency Alert 0 (TEA 0) - Termination.When the declaring Entity is able to respect IROL requirements and is no longer concerned with its ability to respect IROLs, it shall request its Reliability Coordinator to terminate the alert.4.1. Notification. The Reliability Coordinator shall notify Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Transmission Operators and Balancing Authorities.RCIS Posting ExamplesEach RCIS posting should be clear and concise. If the actions are being taken as a result of a contingency, the contingency should also be identified as the cause.The following are examples of possible of RCIS postings:TEA 1(name of RC) is declaring a TEA 1 on the (name of the interface).TEA 2(name of RC) is declaring a TEA 2 on the (name of the interface). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of (type of load management procedures that have been or expected to be implemented ie voltage reduction, curtailable load reductions) of relief has been (or is expected) to be implemented to respect the limit. These actions are expected to last the next (length of time ? hours/days) and should be sufficient to prevent the need for Firm load shedding.TEA 3(name of RC) is declaring a TEA 3 on the (name of the

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		interface). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of Firm Load curtailments have been (or is expected) implemented to respect the limit. These actions are expected to last the next (length of time ? hours/days).Contingency ExampleIf the TEA is being declared as a result of a contingency the message could be modified simply by adding the contingency description as below:(name of RC) is declaring a TEA 2 on the (name of the interface). This is a result of a contingency on (name of the interface or contingent element). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of (type of load management procedures that have beenStandard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 10 of 17Effective Date: October 1, 2007or are expected to be implemented i.e. voltage reduction, curtailable load reductions) to respect the limit. These actions are expected to last the next (length of time ? hours/days) and should be sufficient to prevent the need for Firm load shedding.UpdatesWhen updating postings only significant changes need be identified. The following is appropriate:(name of RC) remains in a TEA (2 or 3) on the (name of the interface). (amount of MW relief) of (type of load management procedures that have been or are expected to be implemented i.e. voltage reduction, curtailable load reductions, firm load reductions) have been implemented (description of the change i.e. increased/reduce by amount of MW change or identify no change).Standard TOP-004-3 ? Transmission OperationsExample #1IROL violation on X No Global Adequacy ConcernsIROL ?X?500 MW - A to B300 MW - B to AIntertie Limit Intertie LimitImp 300 Imp 200Exp 200 Exp 100EEA1 No2 No3 NoTEA1 Yes2 Yes3 YesIn this example the available generation in A is in excess of its load requirements. The available generation in B is less than its load requirements. Area B will be relying on the full transfer capability of the interface ?X? plus an additional import of 100 MW to the maximum limit on the intertie in Area B. With the implementation of the interruptible load and V/R the firm load requirements in B cannot be met without the use of Firm load shedding.In this scenario an EEA is not required as the BA is able to meet its globalBA Total Load 2,500 MWBA Total Gen 2,900 MWBAImpLimit500MWZone AZone BLoad 1,500 MWLoad 1,000 MWGen available 2,800 MWGen available 100 MWImp 0 MWImp 100 MWExp 0 MWExp 0 MWInterruptible 50 MWLoadInterruptible 50 MWLoadV/R 50 MWV/R 50 MWBalancing Authority X Adopted by Board of Trustees: November 1, 2006 Page 11 of 17Effective Date: October 1, 2007Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 12 of 17Effective Date: October 1, 2007load/generation requirements .When this situation is forecast a TEA 1 should be issued to indicate the potential concerns with the ability to respect the IROL limit X without the use of load management procedures. When load management procedures are implemented in Real Time to respect the IROL X, a TEA 2 should be issued.When Firm load is curtailed to respect the limit a TEA 3 should be issued.Standard TOP-004-3 ? Transmission OperationsExample #2Global Adequacy DeficiencyNo IROL ViolationIROL ?X?500 MW - A to B300 MW - B to AIntertie Limit Intertie LimitImp 300 Imp 200Exp 200 Exp 100EEA1 Yes2 Yes3 NoTEA1 No2 No3 NoIn this example the available generation in A is less than its load requirements. The available generation in B is less than its load requirements. There is a Global Adequacy deficiency after considering full import capability and

Organization	Yes or No	Question 6 Comment
		utilization of interruptible load and V/R.BA Total Load 2,500 MWBA Total Gen 1,800 MWZone AZone BLoad 1,500 MWLoad 1,000 MWGen available 900 MWGen available 900 MWImp 300 MWImp 200 MWExp 0 MWExp 0 MWInterruptible 100 MWLoadInterruptible 50 MWLoadV/R 50 MWV/R 50 MWBalancing Authority X Adopted by Board of Trustees: November 1, 2006 Page 13 of 17Effective Date: October 1, 2007Standard TOP-004-3 Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 14 of 17Effective Date: October 1, 2007?EEA procedures should be followed?There is no need for a TEA to be issuedStandard TOP-004-3 ? Transmission OperationsExample #3Global Adequacy DeficiencyIROL ViolationIROL ?X?500 MW - A to B300 MW - B to AIntertie Limit Intertie LimitImp 300 Imp 200Exp 200 Exp 100EEA1 Yes2 Yes3 NoTEA1 Yes2 Yes3 YesIn this example the available generation in A meets its load requirements. The available generation in B is less than its load requirements. There is a Global Adequacy deficiency after considering full import capability. There is also an IROL violation at X in the direction of A to B to meet the load requirements in B depending on where load management procedures are implemented.Adopted by Board of Trustees: November 1, 2006 Page 15 of 17Effective Date: October 1, 2007?An EEA 1 and a TEA 1 should be issued to identify the potential issuesBA Total Load 2,500 MWBA Total Gen 1,700 MWBAImpLimit500MWABLoad 1,500 MWLoad 1,000 MWGen available 1,600 MWGen available 100 MWImp 300 MWImp 200 MWExp 0 MWExp 0 MWInterruptible 100 MWLoadInterruptible 50 MWLoadV/R 50 MWV/R 50 MWBalancing Authority X Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 16 of 17Effective Date: October 1, 2007 When load management procedures are implemented to manage the transfer from A to B a TEA 2 should be issued (assumes B will be deficient before the global deficiency occurs).?An EEA 2 should be issued when load management procedures are being implemented in A to manage global requirements. TEA 3 should also be issued when Firm load is shed in B to meet the load requirements in B while respecting the IROL.Standard TOP-004-3 Transmission OperationsExample #4Transaction CurtailmentsIROL X 500 MW - A to B300 MW - B to AIntertie Limit Intertie LimitImp 300 Imp 200Exp 200 Exp 100EEA1 No2 No3 NoTEA1 No2 No3 NoIn this example there are no global adequacy concerns. There is an export transaction in B that is causing a limit concern on X in the A to B direction. With the available generation in B plus the transfer capability there is no concern for violating the IROL limit. The transaction is creating a situation where it will be required curtailed at some point to prevent the IROL violation. Assuming the TLR procedure would be effective at relieving this constraint regardless of the TLR level (at either the TLR 3 or 5 level) no TEA would be required as there is no concern that the IROL can't be respected with control actions that don't involve load management procedures.BA Total Load 2,500 MWBA Total Gen 2,500 MWBAImpLimit500MWABLoad 1,500 MWLoad 1,000 MWGen available 2,000 MWGen available 500 MWImp 200 MWImp 0 MWExp 0 MWExp 100 MWInterruptible 100 MWLoadInterruptible 50 MWLoadV/R 50 MWV/R 50 MWBalancing Authority X Adopted by Board of Trustees: November 1, 2006 Page 17 of 17Effective Date: October 1, 2007
Response: As per the wording of the attached document**: "**may be initiated only by a Reliability Coordinator' this certainly seems to say that this requirement		

Organization	Yes or No	Question 6 Comment
belongs in the IRO family of standards as opposed to the TOP family of standards. This request should be forwarded to Project 2006-06.		
SERC OC Standards Review Group	Yes	TOP-001 R2 - The phrase "shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities" could cause compliance issues due to the resulting subjectivity of the identification of other reliability entities. We recommend that it replaced with "shall coordinate its respective operations known or expected to have a reliability impact on adjacent reliability entities". It should be the responsibility of the adjacent reliability entity to further coordinate, if necessary, other appropriate reliability entities. The Measures and VSLs would need to be modified accordingly. Top-001, Requirement 4 - we suggest changing other reliability entities to adjacent reliability entities. TOP-002 R2 uses the word "plan" as a verb, and then it is referenced in R3 as a noun. This is propagated in the Measures and VSLs. We suggest the following wording change in R2: The Transmission Operator shall have a coordinated plan...... ? TOP-003 R1.2 We disagree with this requirement and we recommend that it be struck. The TOP and the BA must be able to specify formats that can be utilized by their processes to ensure reliability.
Response: The word 'coordinate' is not used in TOP-001-2, Requirement R2 but upon review the SDT has modified the wording to address your concern about affected Transmission Operators. **TOP-001-2, R2.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions. If there are known 3rd party impacts, it only makes sense that all entities need to be informed. 'Other' provides that flexibility and includes adjacent. The SDT sees no reason to change the wording in TOP-002-3, Requirements R2 & R3. Plan can be both a noun and a verb and the usage here is self-explanatory. The SDT believes that R1.2 is a reasonable attempt to solve the problem where there are 2 different system involved. Deleting the requirement doesn't solve the problem. No change made.		
Dominion Resources Inc.	Yes	TOP-001 uses the term reliability entities in the purpose statement while TOP-003 uses the term functional responsibilities. The Functional Model uses the term Responsible Entities. We suggest that NERC and the SDT make every effort to use consistent terms. We continue to have concerns with the current standards review/approval process. Having to make comments on new draft standards that are predicted upon other draft standards that have not been approved is a non-productive process.As stated in the implementation plan ?Changes made in this project

Organization	Yes or No	Question 6 Comment
		to TOP-005-1, R1; TOP-007-0, R4 are dependent on corresponding changes being approved in Project 2006-06 Reliability Coordination: COM-001-1: Telecommunications? COM-002-2: Communications and Coordination? IRO-001-1: Reliability Coordination Responsibilities and Authorities? IRO-002-1: Reliability Coordination Facilities? IRO-014-1: Procedures to Support Coordination between Reliability Coordinators? IRO-015-1: Notifications and Information Exchange between Reliability Coordinators? IRO-016-1: Coordination of Real-Time Activities between Reliability Coordinators? PER-004-1: Reliability Coordination Staffing? PRC-001-1: System Protection Coordination?
Response: The SDT has reviewed the wording indicated and sees no reason for confusion or concern and has not made any changes to these statements. The Standards Committee and NERC staff has the responsibility for coordinating multiple standards and deciding what can be posted concurrently. The SDT has no control over this.		
MRO NERC Standards Review Subcommittee	Yes	See response to question number 5 which is ?After the review of the paragraph 1612 of the FERC final order 693, the MRO NSRS would like them to be more specific about the type of outages and consistent with the Reliability Coordinator's requirement; the Reliability Coordinator has a wide-area view. How would this country-wide advance notice improve reliability for two independent systems not physically interconnected? In TOP-001-1 R1, what is a reliability directive? Should this be defined? The NERC standard COM-002-2 talks about the RC issuing a reliability directive, what is a directive? Not every communication is a directive; please clarify what is a reliability directive. Should each directive start off by stating that it's a directive and that 3 way communication should be used? (In the MISO Business Practice RTO-OP-002 R7, Telephone Communications Protocol, section 3.2.1, when issuing a Reliability Directive the following must be stated: This is a Reliability Directive and I will need you to repeat it back.) Other MISO Business Practices which discuss reliability directives are RTO-BPM-006-R2 and RTO-EOP-003-R8. The current standard TOP-002-2a includes an interpretation of R11 stating among other things that a unique study is not needed for each operating day. The MRO NSRS recommends revising the TOP-002-3 R1 to include this interpretation. For the TOP-003-1 R1, Each Transmission Operator and Balancing Authority shall have a documented specification for data to support its Real-time monitoring and reliability assessments required to fulfill their respective responsibilities per the NERC Functional Model., the MRO NSRS believes that this phrase NERC Functional Model should be removed since it is unclear as it reads now and it should be replaced with R1.1, R1.2, and R1.3.
Response: See the response to question 5.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">The Reliability Coordination SDT is proposing the following as a definition of reliability directive.

Reliability Directive: A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency,

Neither the measure nor the requirement states that you must have a power flow study for each day. The measure states that you COULD have a power flow study as one method of measuring compliance. The SDT feels that this is clear and no change is necessary.

The SDT agrees and has modified the requirement accordingly.

TOP-003-1, R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include:</td></tr>
<tr><td>FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool</td><td>Yes</td><td>We generally support the revised standards, but did have a few additional comments:? The data retention is significantly longer than earlier standards, e.g., three years rather than 3 months, and the data retention is not consistent between standards, e.g., TOP-001-2 is one year, TOP-002-3 is six months, TOP-003-1 and TOP-004-3. What is your reasoning behind these changes and the inconsistencies between them? Also, saving daily operating data for three years seems a long time.

TOP-002-3 R1 probably ought to refer to TOP-003-1 as one of the sources of data for the assessments.

Do the standards require current day plans? TOP-002-3 and IRO-004-1 only covers next day. Are we making current day equivalent to real-time, and therefore not requiring a plan for the current day??

TOP-002-3 R1 assigns the same task to the TOP that the RC has in IRO 004 1 R1, although not as confusing as real-time operations with two entities responsible for the same thing, as discussed above in the comments to TOP-001-2, this also has potential for confusion of roles, responsibilities and actions. Should only one entity be responsible for next day plans, e.g., the RC? Or is the distinction that RCs study interfaces, whereas the TOPs assess its entire system? If so, should such a distinction exist?</td></tr>
<tr><td colspan="3">Response: The SDT has changed the data retention for TOP-003-1, Requirements 2, 3, and 5 to 90 days.

The SDT finds no reliability reason to specify the data sources employed in TOP-002-3. That seems more like a ‘how’ as opposed to a ‘what’. No change made.

The next day plan referenced here becomes the basis of the current day plan today. No change made.

The Transmission Operator is responsible for its area and the Reliability Coordinator is responsible for theirs. The SDT sees no conflict here. No change made.</td></tr>
<tr><td>Colmac Clarion</td><td>Yes</td><td>During 'blackout' that resulted in this program, GOP's received more intial information on problem and expected recovery from CNN then from 'chain of command'. If response is expected inclusion in information stream must also be included.</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
Response: The SDT can not respond unless specific references and suggestions are provided.		
Xcel Energy	Yes	In general, we appreciate the drafting team's work and feel the drafted standards are a positive move towards more simplified requirements. However, we do have some concerns, detailed below. TOP-001>We feel the new R3 should also be applicable to BAs & GOs. >R4 - The phrase reliability entities needs definition. It is not clear who is being referenced. >R6 consider adding language to include SOLs. TOP-002>R1- We assume that the use of the defined term ?Contingency? implies N-1 contingency planning. Yet, it is not clearly stated as such and therefore open to some interpretation. We recommend adding language to clarify, similar to the current version. >R2 What is the intent here? Please clarify if planning is intended to entirely prevent the exceedence of an IROL, or to not exceed an IROL Tv. >R3 - The phrase reliability entities needs definition. It is not clear who is being referenced. >Deletion of the current R3 raises a concern as to what now requires LSEs and GOPs to coordinate their planning. This can present problems with TOPs and BAs attempting to collect needed data. >Deletion of current R8 where is this covered elsewhere? TOP-003>R1.1 long term needs more definition; we recommend changing to operating horizon >R1.1 We do not believe it was the drafting teams intent to require outage reports of all BES components (breakers, etc), nor do we feel that is reasonable. We recommend the addition of a clarifying statement such as: BES components specified by the Transmission Operator and Balancing Authority. >R5 uses the phrase immediate responsibility suggest changing this to responsible for real time operations. >It is not yet clear where the current R2 and R3 are being moved to. The previous draft indicated they would be moved to IRO standards. Please provide the link to those drafts or the project they are being worked under.
Response: TOP-001-2, R3: The obligation is on the Transmission Operator to coordinate emergency assistance and is not a task for the Balancing Authority or Generator Operator. No change made. R4: Reliability entities are the entities certified by NERC as such. No change made.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">R6: The industry is indicating approval of having this requirement limited to IROL and IROL T_v. No change made.

TOP-002-3, R1: The SDT has modified the wording to address this concern.

TOP-002-3, R1. Each Transmission Operator shall have an assessment for the next day’s operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential single Contingency events.

R2: The statement is to plan to avoid exceedances of an IROL with no timing element involved. No change made.

R3: Reliability entities are the entities certified by NERC as such. No change made.

R3: TOP-003-1 covers the data requirements. No change made.

R8: The SDT assumes you mean the current approved standard as opposed to what was posted. This was deleted because Balancing Authorities can’t deliver anything. No change made.

TOP-003-1, R1.1: Long term is ‘defined’ by the use of the Operations Planning Time Horizon which is limited to one year.

R1.1: The SDT agrees and has changed the requirement accordingly.

TOP-003-1, R1.1, bullet #1: Long term outages of Bulk Electric System equipment, as specified by the Transmission Operator or Balancing Authority,

R5: The SDT has deleted that terminology.

TOP-003-1, R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities , the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments.

R2: This is being covered in Project 2006-06.</td></tr>
<tr><td>Ameren</td><td>Yes</td><td>The team has done a significant amount of work in getting these standards cleaned up. There was too much duplication and uncertainty.</td></tr>
<tr><td>PJM's NERC and Regional Coordination Department</td><td>Yes</td><td></td></tr>
<tr><td>PacifiCorp</td><td>Yes</td><td></td></tr>
<tr><td>WECC</td><td>Yes</td><td></td></tr>
<tr><td>NextEra Energy Resources, LLC</td><td>Yes</td><td></td></tr>
</table>

Organization	Yes or No	Question 6 Comment
American Electric Power	Yes	
E.ON U.S.	Yes	
Con Edison System Ops		No single concern. Each revision should be analyzed on its own merits.
Manitoba Hydro	Yes	
Entergy Services	Yes	
Puget Sound Energy	Yes	
Response: Thank you for your response.		

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Real-time Operations Standards — Project 2007-03

The Real-time Operations Standard Drafting Team thanks all commenters who submitted comments on the third draft of the standards for Real-Time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from August 25, 2009 through September 24, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 26 sets of comments, including comments from more than 80 different people from over 45 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Changes have been made to the project standards as indicated below due to industry comments and miscellaneous updates:

Minor wordsmithing was done to TOP-001-2, Requirement R1 to add 'identified' to Reliability Directive so that there can be no confusion – the listed functional entities are only responsible for 'identified' Reliability Directives.

Requirement R2 was added to TOP-001-2 to allow a responsible entity to inform the Transmission Operator is it is unable to perform a Reliability Directive.

TOP-001-2, Requirement R3 was altered to tie the cited Emergencies to those noted in the assessment of the Operational Planning Analysis. This ties down the 'known or expected' language that caused some entities concern.

The Generator Operator was removed from TOP-001-2, Requirement R5 based on comments received which indicated that the Generator Operator did not posses the knowledge to participate in the required actions. This requirement was also changed to use the defined terms "Adverse Reliability Impact" to clarify what 'reliability impact' was involved and "Transmission Operator Areas" to clarify the portion of the BES involved.

TOP-001-2, Requirement R6 was added. This requirement is currently TOP-003-0, Requirement R3. The SDT believed that this requirement was going to be handled by another SDT and had originally deleted it from Project 2007-03. However, that is no longer the case and it is being added back in at this time.

TOP-001-2, Requirement R7 has had clarifying language added to show that the System Operating Limits identified in Requirement R8 are part of this requirement.

Requirement R8 of TOP-001-2 has been altered to indicate that the System Operating Limits cited will have been identified in the Operational Planning Analysis required in TOP-002-3, Requirement R1.

TOP-001-2, Requirement R9 was added to accommodate the addition of System Operating Limits in Requirement R8 similar to what was done in Requirement R7 for IROLs.

TOP-001-2, Requirement R10 has had some minor wordsmithing changes for additional clarity.

TOP-001-2, Requirement R11 has been clarified to indicate the System Operating Limits identified in Requirement R8 must be included here as well.

Requirements R12 through R14 have been added to TOP-001-2 to address a FERC Order 693 directive on minimum capabilities for Transmission Operators. Originally this directive was going to be handled by Project 2009-02, Real-time Reliability Monitoring and Analysis Capabilities but that project is now on indefinite hold so the need to address the directive has returned to Project 2007-03.

The VSL's for Requirements R3, R5, R8, and R10 of TOP-001-2 have been adjusted to align with the most recent VSL guidelines.

TOP-002-3, Requirement R1 was altered to make use of a defined term 'Operational Planning Analysis' that clearly shows the intent of what is required. A rationale text box was added to describe the reasoning for this change. TOP-002-3, Requirement R2 has been clarified to show that the System Operating Limits discussed in TOP-001-2 are included here.

Data retention for TOP-002-3 has been modified to agree with the latest guidelines.

The VSL's for TOP-002-3, Requirement R3 have been adjusted to align with the latest guidelines.

TOP-003-2, Requirements R1 and R5 have been changed to align with the addition of 'Operational Planning Analysis' in TOP-002-3.

TOP-003-2, Requirement R3 has been clarified so that monitoring and status are both explicitly included.

Measure M5 of TOP-003-2 has been changed to more clearly state what evidence is required.

The VSL's for Requirements R2 and R3 of TOP-003-2 have been changed to align with the latest guidelines.

Due to the number of comments received requesting an additional posting, and the number of changes made to the revised standards, the SDT agrees that an additional posting is required, however the team also recommends that this posting take place in parallel with an initial ballot.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Greg Mason	Dynegy Generation	NPCC	5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
17.	Bruce Metruck	New York Power Authority	NPCC	6
18.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
19.	Robert Pellegrini	The United Illuminating Company	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
22.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		SERC	5
2.	Mike Garton		NPCC	6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Gerald Beckerle, Vice Chair - SERC Operating Committee	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Neagle	AECI	SERC	1, 3, 5
2.	Gene Delk	SCE&G	SERC	1, 3, 5
3.	J. T. Wood	Southern	SERC	1, 3, 5
4.	Steve Fritz	ACES Power Marketing	SERC	6
5.	Alan Jones	Alcoa	SERC	1, 5
6.	Hugh Francis	Southern	SERC	1, 3, 5
7.	Bob Dalrymple	TVA	SERC	1, 3, 5, 9
8.	Chad Randall	E.ON.US	SERC	1, 3, 5
9.	George Carruba	EKPC	SERC	1, 3, 5
10.	Brad Young	E.ON.US	SERC	1, 3, 5
11.	Timmy LeJeune	Louisiana Generating	SERC	1, 3, 6
12.	John Troha	SERC Reliability Corp.	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Ben Li	IRC Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

1. Anita LEE	AESO	WECC	2
2. Lourdes ESTRADA-SALINERO	CAISO	WECC	2
3. H. Steven MYERS	ERCOT	ERCOT	2
4. Matt GOLDBERG	ISO-NE	NPCC	2
5. Bill PHILLIPS	MISO	RFC	2
6. Jim CASTLE	NYISO	NPCC	2
7. Patrick BROWN	PJM	RFC	2
8. Charles YEUNG	SPP	SPP	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hohlbaugh	FirstEnergy	RFC	
2. Dave Folk	FirstEnergy	RFC	
3. John Reed	FirstEnergy	RFC	
4. John Martinez	FirstEnergy	RFC	
5. Andy Hunter	FirstEnergy	RFC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Deb Schaneman	Platte River Power Authority Operations Group	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection
1. Terry Baker	Platte River Power Authority	WECC	1, 3, 5
2. John Collins	Platte River Power Authority	WECC	1, 3, 5
3. John Powell	Platte River Power Authority	WECC	1, 3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Burns	Transmission Technical Operations	WECC	1
2. Tim Loepker	Transmission Dispatch	WECC	1
3. Rebecca Berdahl	Power Long Term Sales & Purchases	WECC	3

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Carol Gerou	NERC Standards Review Subcommittee										X

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS Corporation	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
4.	Ken Goldsmith	Alliant Energy	MRO	4
5.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Jason L Marshall	Midwest ISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Thomas	Illinois Municipal Electric Agency	SERC	4
2.	Joe O'brien	NIPSCO	RFC	1
3.	Barb Kedrowski	We Energies	RFC	3, 4, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Individual	Michael Davis	WECC RC										X
11.	Individual	Hugh Francis	Southern Company	X		X		X					
12.	Individual	James A Maenner	James A Maenner								X		
13.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
14.	Individual	Ed Stein	self								X		
15.	Individual	Michael Ayotte	ITC Holdings	X									
16.	Individual	Mike Gentry	Salt River Project	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Individual	Ed Davis	Entergy Services, Inc	X		X		X	X				
18.	Individual	Larry Watt	Lakeland Electric	X		X		X					
19.	Individual	Daniel Herring	The Detroit Edison Company			X	X	X					
20.	Individual	Howard Rulf	We Energies			X	X	X					
21.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
22.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
23.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
24.	Individual	Martin Bauer	US Bureau of Reclamation					X					
25.	Individual	Jason Shaver	American Transmission Organization	X									
26.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. TOP-001-2: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: A number of comments were received requesting clarification of terminology or intent within the various requirements. The SDT has answered all of the comments and made a number of the requested changes as shown below. However, no changes were made as to content or context of the requirements.

Due to industry comments, the following changes were made to the standard:

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

R8. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.

M1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, , evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M3. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and all other Transmission Operators that it knew or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M5. Each Transmission Operator shall make available upon request, evidence that operations it coordinated its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5 unless conditions did not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

R8 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5%	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more

	the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**
R10 VSL	N/A	N/A	N/A	The Transmission Operator did inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL as identified in Requirement R8, has been exceeded.

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	No	(1) In R1, reliability directive is capitalized in indicating (or implying) it is a defined term. But this term has not yet been defined despite our understanding that there are currently three SDTs that are reviewing and/or attempting to define this term and the term (Directive). We suggest to make this term lower case until it is defined. (2) R2: the revised wording seems a bit odd as the phrase "expected to be affected" could be interpreted to be describing the actual or anticipated Emergency conditions. We suggest R2 to be revised to: "Each Transmission Operator shall inform its Reliability Coordinator and known or expected to be affected Transmission Operators of actual Emergency and anticipated Emergency conditions" to enhance clarity. Alternatively, we propose inserting a comma after "expected to be affected". (3) R3: We suggestion to add a comma after "comparable emergency procedures". (4) R5 to R8: The very issue that we brought up during the last 2 postings came under the spot light with the changes made at this posting. The SDT in response to industry comments made changes to qualify the SOLs whose exceedances are to be reported (in R7) based on a list of SOLs identified in R6 (the SDT added this requirement for this reason). While we don't think such identification is necessary, and in fact may expose the system to unreliability since such a list would be selective and hence bound to miss some SOLs that affect reliability, we nevertheless are encouraged by the changes and the addition since it is a step in the right

Organization	Yes or No	Question 1 Comment
		direction. In our view though, it did not go far enough. However, without an explicit requirement that the TOP shall operate within all SOLs (as in the case for IROL in R5) and to act or direct others to act to mitigate the magnitude and duration of exceeding all SOL within some time frame (as in the case for IROL in R8), the requirements to identify a list of SOLs (in R6) and informing its Reliability Coordinator of actions being taken to return the system to within limits when one of these SOLs has been exceeded (in R7), appear inconsistent. We therefore recommend that R5 be altered as follows:R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL Tv, and each other System Operating Limit (SOL) and its associated time period as determined by the TOP. Similar to their IROL counterparts, operating within all SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations, although for IROLs the interconnected system impact is readily obvious than for SOLs. The same principle holds true for day-ahead operational planning so that the needed control measures can be identified and made available in advance to prevent operating in excess of SOLs and to mitigate exceedances if and when they occur during day at hand and real-time operations. (5) As pointed out in our previous comments, we did not agree that VSLs should be determined based on the number of times a requirement was violated. While it is appropriate to determine the VSLs for R6 based on the number of SOLs that support local area reliability not reported to the RC since these numbers represent the extent of missing the total set, the same approach should not be applied to the determination of R7 since the progressive VSLs appear to make a difference between IROL and SOL (Note: the former has a Severe VSL for failing to notify one exceedance whereas for the latter the VSLs are graded based on the number of SOLs whose exceedances a TOP failed to notify its RC). Note that R7 requires that the TOP inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. The requirement does not make any distinction between IROL and SOL, and requires that there shall not be even a single incident that the TOP does not inform its RC of actions being taken to mitigate an IROL or SOL exceedance. Hence, missing even one SOL would violate the bulk of the intent of R7. We suggest the VSLs for Low, Moderate and High be removed, and revise the VSL for Severe to:The Transmission Operator did not make available evidence that it had informed itsReliability Coordinator of actions being taken to return the system to within limit when an IROL or SOL has been exceeded.
Northeast Power Coordinating Council	No	(1) In R1, reliability directive is capitalized in indicating (or implying) it is a defined term. But this term has not yet been defined despite our understanding that there are currently three SDTs that are reviewing and/or attempting to define this term and the term (Directive). We suggest to make this term lower case until it is defined. (2) R2: the revised wording seems a bit odd as the phrase “expected to be affected” could be interpreted to be describing the actual or anticipated Emergency conditions. We suggest R2 to be revised to: “Each Transmission Operator shall inform its Reliability Coordinator and known or expected to be affected Transmission Operators of actual Emergency and anticipated Emergency conditions” to enhance clarity.

Organization	Yes or No	Question 1 Comment
		Alternatively, we propose inserting a comma after “expected to be affected”. (3) R3: Add a comma after “comparable emergency procedures”. (4)Similar to their IROL counterparts, operating within all SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations. (5) As pointed out in our previous comments, we did not agree that VSLs should be determined based on the number of times a requirement was violated. While it is appropriate to determine the VSLs for R6 based on the number of SOLs that support local area reliability not reported to the RC since these numbers represent the extent of missing the total set, the same approach should not be applied to the determination of R7 since the progressive VSLs appear to make a difference between IROL and SOL(Note: the former has a Severe VSL for failing to notify one exceedance whereas for the latter the VSLs are graded based on the number of SOLs whose exceedances a TOP failed to notify its RC). Note that R7 requires that the TOP inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. The requirement does not make any distinction between IROL and SOL, and requires that there shall not be even a single incident that the TOP does not inform its RC of actions being taken to mitigate an IROL or SOL exceedance. Hence, missing even one SOL would violate the bulk of the intent of R7. We suggest the VSLs for Low, Moderate and High be removed, and revise the VSL for Severe to:The Transmission Operator did not make available evidence that it had informed itsReliability Coordinator of actions being taken to return the system to within limit when an IROL or SOL has been exceeded.

Response: (1) Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.

> **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

(2) The SDT has revised Requirement R2 (now Requirement R3) based on your comments and the comments of others.

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

(3) The comma has been added as suggested. (Note – Requirement R3 is now Requirement R4.)

> **R4**. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

(4) The SDT agrees that operating within a certain subset of SOLs such as IROLs is fundamental to reliability. However, the SDT does not believe operating within all SOLs is necessary and actually reduces reliability by eliminating an operator’s operational flexibility such as reducing the life of a piece of equipment

Organization	Yes or No	Question 1 Comment

to avoid shedding firm end use Load. However, the SDT realizes that there may be a certain set of SOLs that are considered important by the Transmission Operator and that would be treated in a similar vein to IROLs. The new Requirement R9 addresses this concern.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.

(5) The SDT has reviewed the various VSLs to assure that they follow the latest guidelines and has revised several of them accordingly. Examples are shown below.

R8 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**
R10 VSL	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL as identified in Requirement R8, has been exceeded.

MRO NERC Standards Review Subcommittee	No	A. In R4, states that the TOP and GOP shall coordinate operations “known or expected” by the TOP that have a reliability impact on other reliability entities. Is the TOP used twice in this requirement the same TOP or neighboring TOPs? Please clarify. B. In R4, the GOP will not know of “known or expected” operations of the TOP. Please clarify. C. In R4, as stated the GOP is required to notify the TOP of “relay and equipment failure and changes to generation”, does this include all relays and all equipment associated with a generator? D. In R4, the reference to the term “Load”, a TOP and GOP don’t have loads. Therefore, how can they be

Organization	Yes or No	Question 1 Comment
		required to coordinate something they don't have? Or E. In R4, the reference to the term "operating conditions", the GOP may not know of a severe or changing "operating condition" that is taking place on the transmission system. F. In R2 and R4, "expected to be affected" would include known. Please strike known. G. Both R5 and R6 require the TOP to identify a sub-set of SOLs that may be larger than the IROL subset ahead of time and notify the RC of what actions it is taking to return the system to within operating limits when they are exceeded. Why is there not a requirement to also operate within those SOLs and return within the SOL if exceeded? H. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages?I. The measures for R5 and R8 need to be clear than they currently are that these are event driven requirements and only data is required if an "event" has occurred.

Response: (A) This is the same Transmission Operator.

(B) The SDT agrees that the Generator Operator will not know of operations on the BES. The requirement has been deleted.

(C) This would include all relays and equipment that could impact the Bulk Electric System. Requirement R4 (now Requirement R5) has been changed to provide greater clarity as to the intent of the requirement.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

(D) A Transmission Operator must be able to forecast and monitor the Load on its portion of the Bulk Electric System. They must be aware of significant changes that could cause changes to expected Load. No change made.

(E) The SDT agrees that the Generator Operator will not know of operations on the BES. The requirement has been deleted.

(F) The SDT disagrees and feels that both terms are needed but has added terminology to clarify the expectation. (Note – Requirement R4 is now Requirement R5.)

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

(G) By definition, IROLs could result in cascading outages, widespread outages, and blackouts. SOLs will not. Thus, the SDT believes that requiring the

Organization	Yes or No	Question 1 Comment

Transmission Operator to operate within all SOLs that are not IROLs would eliminate the Transmission Operator's operational flexibility. However, the SDT realizes that there may be a certain set of SOLs that are considered important by the Transmission Operator and that would be treated in a similar vein to IROLs. The new Requirement R9 addresses this concern.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.

(H) The SDT has reviewed the VSLs for Requirement R8 and revised them based on the latest guidelines.

R8 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**

Bonneville Power Administration	No	Comments: The term "Reliability Directive" needs to be added to the NERC Glossary of Terms (it was not in the April 2009 version).
Platte River Power Authority Operations Group	Yes	In R1 Reliability Directive is capitalized as a defined term but isn't in the NERC Glossary of Terms or Definitions or the Terms Used in Standard section of version 2 of the standard. Where is this term defined?
IRC Standards Review Committee	No	Requirement 1: Reliability Directive, as a defined term has been introduced and the definition has not been provided in this posting. If the intent is to use this as a defined term anticipating that it will be defined and approved soon under a different project, then we suggest these standards not be put up for balloting until the term is approved.

Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>Ed Stein - self</td><td>No</td><td>I do agree with most every thing However I do not understand what is meant by the phrase "expected to affect" a TO. How does the TO experiencing the emergency know if his emergency affect every TO. Granted he should know of the main ones but can he be sure that a remote line is affected that has a 2-5% response factor.</td></tr>
<tr><td colspan="3">Response: The SDT has made a clarifying change to the requirement which should alleviate your concern.

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.</td></tr>
<tr><td>ITC Holdings</td><td>No</td><td>In R2, strike the words “known or”.

In R4, remove the added words “by the Transmission Operator” from the second sentence . The addition of this phrase implies that the Generator Operator does have the obligation to initiate the coordination of changes in generation with the transmission operator. The requirement is clearer without this phrase.

In R4, change the wording to “Such operations MAY include”? We believe the intent of the sentence was only to provide a list of examples.

R6 requires the TOP to identify a sub-set of SOLs that is larger than IROLS and “support its local area reliability”. It is unclear what criteria a TOP would use to identify this subset, which will lead to inconsistent implementation and confusion. The TOP should inform the RC of all SOLs and the actions being taken to address any SOL exceedance which can be accomplished via SCADA or other means of action and communication when necessary.

The measures for R5 and R8 need to be clear that these are event driven requirements and only evidence is required if an “event” has occurred.</td></tr>
<tr><td colspan="3">Response: The SDT feels that the term ‘known’ has a different connotation than ‘expected’ and therefore both are required. However, the SDT has made clarifying changes so that expectations are clear. .

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

The SDT agrees with the second suggestion for Requirement R4 (now Requirement R5) and has made that change. However, the SDT does not agree with the deletion of Transmission Operator that was suggested and has retained it in the requirement.

R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. Based on comments received during the first and second posting, the industry did not reach a consensus that all SOL exceedances should be reported. The majority (it was a small majority) of responders felt that some subset of SOL exceedances should be reported. They felt the subset should be greater than IROLs but less than all SOLs. The remaining respondents were split between only IROLs and all SOLs. This split was likely based on the differing characteristics of the BES in various areas. Thus, the SDT felt drafting the requirement as is represented a reasonable compromise because the Transmission Operators could report the appropriate amount of SOLs based on the characteristics of their portion of the BES. Few additional comments have been received on this issue during this posting, thus the SDT assumes the industry largely agrees this is a reasonable compromise. The SDT feels that the measures are clear as written and has not made a change.		
SERC OC Standards Review Group	No	Is Reliability Directive a defined term since it is capitalized in R1 and throughout the Standard, but not currently found in the NERC Glossary of Terms. R2 We suggest that “other transmission operators” should be changed to “adjacent transmission operators”. R3 What is specifically meant by the words, “emergency assistance”? For example, do the words as written require a utility to provide line crews to assist in storm restoration? We suggest that the language be tightened up to focus emergency assistance on those things that were intended by the language. R4 we suggest removing “and Generator Operator” and the term “by the Transmission Operator” from the first sentence. It appears that the original wording implies that the Generator Operator would have knowledge of conditions on the transmission system. We also suggest removing the last sentence listing some but not all items that may have operating impacts and in which communications is necessary, concerns the SERC OC Standards Review Group. R6 We suggest revising R6 to read: Each Transmission Operator shall inform its Reliability Coordinator of any System Operating Limits (SOLs) which, while not IROLs, will require mitigating actions if exceeded. The current word “all” seems to indicate that every SOL would be in this list. R8 Why is R8 needed ? it appears to be a duplication of R5 and the two could be combined. General comment on measures: Measures that are event driven need to be clear that evidence would only be required if an event occurred. That is, the entity should not have to prove a negative.
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry. **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		

Organization	Yes or No	Question 1 Comment
The SDT discussed and felt that it is possible that some Transmission Operators could affect one another even if they are not adjacent as a result of sharing ties. Thus, no change has been made. R3 – Emergency assistance is not a defined term and could be different from entity to entity. The SDT can't define this term and doesn't feel that it is necessary. Each Transmission Operator will respond according to its set policies and procedures as required by EOP-001-2. No change made. The SDT agrees that the Generator Operator will not know of operations on the BES. However, the Generator Operator may know that his unit is critical to reliability. If his unit is critical to reliability, the SDT expects the Generator Operator should notify the Transmission Operator of all known issues that could reasonably be expected to cause the unit to be at a greater likelihood to be forced out. In Requirement R4 (now requirement R5), the SDT has modified the listing to reflect that it is not all inclusive based on comments from other respondents. **R5**. Each Transmission Operator shall coordinate its respective operations known or expected to have a Burden on the portion of the BES of other reliability entities with those entities unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, Load, or operating conditions. The SDT has modified the wording of Requirement R6 (now Requirement R8) to provide greater clarity. **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.** Requirements R5 & R8 (now Requirements R7 & R10) are slightly different and thus serve slightly different reliability goals. Requirement R7 (now Requirement R8) requires the Transmission Operator to operate within an IROL. Requirement R10 (now Requirement R11), however, requires the Transmission Operator to mitigate an exceedance if one has occurred. For example: If an exceedance occurs and goes away on its own within T_v, there is no violation of Requirement R7. However, if that exceedance occurs and the Transmission Operator doesn't act to mitigate it within T_v then they are in violation of Requirement R10. No change made. The SDT feels that the measures are clear as written and has not made a change in this regard.		
American Electric Power	No	It's our understanding that a definition of the term for a Reliability Directive (RD) may be currently under development/review/approval. However, since RD is not currently found in the NERC glossary, we request that it be added to the definition section of this standard. For example, are base points issued by the market area of an RTO considered an RD? Is there a method to distinguish such base points as constituting an RD from those that are not RDs? The team correctly capitalizes "Transmission" and "Load" since they are terms included in the NERC dictionary and does not capitalize "generation" since it is not included. It would seem that adding the term to NERC glossary would be the best resolution, but, in the interim, it should be well defined within the context that it is being used in any requirement (refer to R4). We are concerned that R5 is a duplication of a requirement in FAC-009 and perhaps others as well. Correspondingly, M5 would also be duplicative. Again, it appears that R6 may be duplicative of FAC-014, R5.2. If not, the phrase "support its local area reliability" should be clarified.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>While we appreciate the team’s efforts to better distinguish IROLs from SOLs in R7., more work is necessary to better define the difference. (e.g., exceeding limits vs. n-1)</td></tr>
<tr><td colspan="3">Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.

Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

The SDT does not believe this is a duplication of the FAC-009 requirements. While many SOLs will be based on a facility rating, not all SOLs are based on facility ratings. Thus, the requirement is needed.

The SDT does not feel that this requirement duplicates FAC-014 as the requirement is specific to those SOLs that are in support of local reliability. The SDT has clarified Requirement R8 to make it clear how the SOLs are identified.

R8. Each Transmission Operator shall inform it’s Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis.

IROLs are a defined subset of SOLs. The SDT believes that the FAC-011-2 and FAC-014-2 standards provide a great amount of detail to distinguish IROLs from SOLs.</td></tr>
<tr><td>American Transmission Organization</td><td>No</td><td>No requirement to define IROL TV.

R6 is already covered in the MOD standards.</td></tr>
<tr><td colspan="3">Response: FAC-014-2, Requirement R5.1.2 requires the Reliability Coordinator to identify the IROL T_V. No change made.

The SDT does not believe that Requirement R6 (now Requirement R9) is covered in the MOD standards. The SDT feels that you may have meant FAC-014-2. The SDT does not feel that this requirement duplicates FAC-014 as the requirement is specific to those SOLs that are in support of local reliability. The SDT has clarified Requirement R8 to make it clear how the SOLs are identified.

R8. Each Transmission Operator shall inform it’s Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis.</td></tr>
<tr><td>Manitoba Hydro</td><td>No</td><td>R.4 - The changes suggested to R. 4 are too vague to result in effective coordination.

What is meant by “expected relay failures”? How is an expected relay failure assessed? What criteria is used to determine what we consider a risk of an expected relay failure - what conditions?

R.6 - is again too vague for making consistent operating decisions. What criteria is applied for identifying SOL’s that support “local area reliability”? What is a local area, how large is it, what reliability criteria is violated on the violation of an SOL</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		R.7 – SOL's identified in R6 are vague.
Response: The intent of Requirement R4 (now Requirement R5) was to require coordination. The SDT has made clarifying changes to the requirement. **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. . Relay failures were cited as an example of conditions that may require coordination. The wording was changed to state 'may' apply so if you have nothing that applies to this condition, you do not have to coordinate them. No change made for this comment but clarifying language was applied. **R5**. Each Transmission Operator shall coordinate its respective operations known or expected to have a Burden on the portion of the BES of other reliability entities with those entities unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, Load, or operating conditions. The SDT has clarified Requirement R8 to make it clear how the SOLs are identified. **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.**		
Electric Market Policy	No	R1 - By capitalizing the term "Reliability Directive", the SDT introduced a discrepancy as this term does not currently exist in the NERC Glossary of Terms. We are opposed to approving revisions to existing or new standards when they are predicated upon references to other "draft" terms, standards, requirements, etc. R4 We have reviewed the various comments made concerning retention of GOP in this requirement, and philosophically agree but find it impossible to determine how GOP can coordinate" its respective operations known or expected by the Transmission Operator to have a reliability impact". without knowing what constitutes "expected to have a reliability impact". The GOP can only coordinate to the extent the TOP has provided predefined information that is required to be coordinated. This information should be included in the Interconnection Agreement or some other agreement that clearly spells out what the GOP is expected to communicate in order to coordinate. We would prefer inclusion of this requirement in TOP-003 as part of R4 (referencing R2 and R3) or we could support the requirement in TOP-001 if it referenced coordination of data required in TOP-003 @ R2 and R3. Also the statement"operating conditions" is sufficiently vague. The SDT needs to clarify what constitutes an operating condition?
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry. **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the		

Organization	Yes or No	Question 1 Comment
recipient is necessary to address an actual or expected Emergency. The SDT agrees and has deleted the requirement. The wording was changed to state 'may' apply so if you have nothing that applies to this condition, you do not have to coordinate them. **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.		
Xcel Energy	No	R1- There is not an associated definition for the term Reliability Directive (nor is there one in the documents associated with Project 2006-06). The term "directive" is the subject of much debate as evidenced by the recent attempt at clarification by the NERC advisory on communications. This term needs to be defined and an opportunity for stakeholder comment, prior to moving this standard to ballot. R1- We feel that GOP should be removed from this requirement. The TOP should coordinate with any entity it necessary. Alternatively, it could be reworded to read: "The TOP shall coordinate operations with the GOP". R2- Should be redrafted to read: "Each Transmission Operator shall inform its Reliability Coordinator and other impacted Transmission Operators of actual or anticipated Emergency conditions."Alternatively, this requirement could be abbreviated to have the TOP notify the RC, as the sharing of that condition by the RC to other impacted entities is covered by the proposed project 2006-06, IRO-001-2 R4: "Each Reliability Coordinator that identifies an expected or actual threat with Adverse Reliability Impacts, within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area." R3- Though addressed in the previous draft version, we continue to disagree with retaining this requirement. Determining if the other entity has implemented a comparable emergency procedure places the burden upon the entity providing assistance to verify completion of internal processes by the requesting entity. This is not reasonable or practical in an emergency situation, and requires the operator to make a subjective decision. Additionally, assuming the requesting entity is compliant with the NERC standards (e.g. EOP-002), there is no reason for the assisting entity to confirm that the deficient entity has properly implemented their comparable procedure. R4- The term "reliability impact" is vague. In reality, every change on the system has a reliability impact, whether it be positive or negative. We recommend instead using the phrase "adverse reliability impact". To what degree must operations be coordinated? The proposed requirement indicates that changes in generation and Load must be coordinated. Does this mean changes in dispatch levels of every generator must be coordinated? How are changes in Load coordinated and what would constitute a significant change worthy of coordination? We recommend striking the last sentence that indicates examples. R5- This implies that the "Interconnection" will specify the IROL Tv. The NERC Glossary defines this at <= 30

Organization	Yes or No	Question 1 Comment
		minutes. Are there IROL Tvs <= 30 minutes? If not, why not just eliminate the hassle of trying to define and keep up with the IROL Tv and just state < 30 minutes in this requirement (and remove the IROL Tv definition)? R8- The phrase “within the IROL’s Tv” should be deleted. The TOP should be directing others to act regardless of whether or not the elapsed time is within or exceeded the IROL Tv. 1.4. Data RetentionThe data retention section implies that compliance is to the Measure as well as the Requirement. We believe that compliance is measured to the Requirement only.

Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

Your second comment regarding Requirement R1 does not appear to be consistent with the requirement. Your comment appears to assume that Requirement R1 is focused on coordination but rather the requirement is for the Generator Operator among others to follow the Transmission Operator’s Reliability Directives. No change made.

The SDT agrees that there is some confusion created by the wording of the requirement and has modified the requirement based on the comments of other respondents in an attempt to provide greater clarity. However, the SDT did not adopt the term ‘impacted’.

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

The SDT disagrees with your comment regarding Requirement R3 (now Requirement R4). Requirement R3 (now Requirement R4) provides the Transmission Operator the option of not providing emergency assistance if the requesting Transmission Operator has not implemented comparable procedures. It does not require the assisting Transmission Operator to verify that the requesting Transmission Operator has implemented comparable procedures. The assisting Transmission Operator could simply provide emergency assistance rather than verifying the requesting Transmission Operator has not implemented its procedures. While the SDT does not favor inclusion of the comparable procedures language, the respondents in previous postings overwhelmingly desired the inclusion. It does not cause a reliability gap so the SDT cannot identify a reason not to include it. No change made.

R4 – The SDT has changed Requirement R4 (now Requirement R5) to provide greater clarity based on your comment and that of others.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

R5 – Earlier standards work determined that the previous definition of IROL was not satisfactory and that the T_v definition was needed to improve the meaning. The SDT does not see a need to remove the definition. Further, the removal of the definition would expand the scope of the SDT beyond the Transmission Operator standards and is not warranted.

Organization	Yes or No	Question 1 Comment
R8 (now Requirement R11) – The SDT agrees the Transmission Operator should be acting with expediency to resolve an IROL. The requirement does not allow the Transmission Operator to wait to resolve the IROL exceedance but rather recognizes that the Transmission Operator requires time to assess how to resolve the exceedance. Assessing is one form of acting and the language of the requirement is appropriate as it is written. No change made. Data retention – The language in the data retention section is standard verbiage that simply states that you must retain the data necessary to measure the compliance with the requirement. No change made.		
FirstEnergy	No	R3 This requirement requires "comparable emergency procedures" be implemented which is appropriate and consistent with the previous standards, but it lacks, and the previous standards lacked, the concept of mitigation. An entity should not be required to shed load for the sake of requiring a neighboring entity to shed load to mitigate the emergency condition. As currently written, in order for an entity to require its neighbor to shed load that will mitigate the emergency condition, the requesting entity is required to shed load first. We suggest this be revised to say, "comparable emergency procedures that mitigate (lessen or eliminate) the impact of the emergency." R6 This requirement is ambiguous. By definition a System Operating Limit is "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: (a) Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)? Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)? Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)? System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)"As written, the TOP will be required to inform the RC of all equipment ratings that "support local area reliability." This could be interpreted as requiring an entity to report equipment ratings for facilities operated at 100 kV or less which we believe is not the intent of the SDT. These facilities certainly support local area reliability on some level but are not monitored by the RC and serve little or no value to the RC.FAC-014-2 requires the TOP in Req. R2 to "establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." Therefore, it appears that TOP-001-2 Req. R6 may not be necessary. However, if the intent of FAC-014-2 Req. R2 is to establish SOLs from an Operations PLANNING horizon (not sure since FAC-014-2 does not include time horizons with the requirements), and the intent of TOP-001-2 Req. R6 is to inform the RC from a REAL-TIME operations horizon, then Req. R6 of TOP-001-2 should be consistent with FAC-014 and written as follows: "R6. Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs) which are consistent with its Reliability Coordinator's SOL methodology."
Response: R3 – The SDT has modified the requirement (now Requirement R4) in response to other commenters. **R4**. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or		

Organization	Yes or No	Question 1 Comment
statutory requirements. R6 – Based on comments from other respondents, the SDT has modified Requirement R5 to use “Burden” rather than reliability impact. The SDT believes this will lessen your concern that facilities below 100 kV are included. Further, the SDT believes this issue is largely an issue around the definition of BES. Standards apply only to the BES and facilities impactive to the BES. Defining the BES is beyond the scope of this SDT. The SDT believes that FAC-014-2, Requirement R2 covers the operating horizon as well. The intent of Requirement R9 is not to duplicate FAC-014-2, Requirement R2 but for the Transmission Operator to identify the subset of SOLs from FAC-014-2, Requirement R2 that impact local area reliability to the point that the Reliability Coordinator may need to become involved. Thus, the Transmission Operator would communicate to the Reliability Coordinator SOL exceedances for this subset of SOLs. The SDT has made a clarifying change to Requirement R6 (now Requirement R8). **R8**. Each Transmission Operator shall inform it’s Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.**		
Duke Energy	No	The definition of “Reliability Directive” drafted by the Reliability Coordination SDT should also be commented on in this TOP effort. We are concerned that the definition is too broad and would encompass what we consider normal communications. A key point of the definition should be that each communication of a Reliability Directive is required to be identified as such to the receiving entity. R2 should say that the TOP shall inform its RC and direct interconnected TOPs. The phrase “known or expected to be affected” opens the TOP to non-compliance if they don’t expect someone to be affected, and it turns out that they are affected. R3 strike the phrase “provided that the requesting entity has implemented its comparable emergency procedures”. In this situation we should not be wasting time getting proof that the requester has implemented their procedures before rendering assistance. R4 is confusing. Relay and equipment failures are not operations; they are operating events. Also, what is meant by the phrase “unless conditions do not permit such coordination” R5 is confusing and appears to duplicate R8. Delete R8 and reword R5 as follows: “Each Transmission Operator shall operate or direct others to operate within IROL Tv for each identified Interconnection Reliability Operating Limit (IROL).” R6 should include identified IROLs in the communication to the RC. Reword R6 as follows: “Each Transmission Operator shall inform its Reliability Coordinator of all identified IROLs and those System Operating Limits (SOLs) which support its local area reliability.” Revise Measures and VSLs to reflect these changes to TOP-001-2
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.		

<table>
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<tr><td colspan="3">
Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.
R2 – (now Requirement R3) The SDT disagrees that only directly interconnected Transmission Operators should be included. It is possible that a Transmission Operator could be adversely impacted by another Transmission Operator that is not directly interconnected. Furthermore, the SDT has made a clarifying change to the requirement wording.
R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.
R3 - While the SDT does not favor inclusion of the comparable procedures language, the respondents in previous postings overwhelmingly desired the inclusion. It does not cause a reliability gap so the SDT cannot identify a reason not to include it.
R4 – (now Requirement R5) Relay failures were cited as an example of conditions that may require coordination. The wording was changed to state ‘may’ apply so if you have nothing that applies to this condition, you do not have to coordinate them.
R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.
The phrase “unless conditions do not permit such coordination” was intended to cover any situation that may prevent coordination from occurring up front. One example that may prevent coordination would be the need to take emergency actions such as ordering a unit to re-dispatch to relieve an IROL.
Requirements R5 & R8 (now Requirements R8 & R11) are slightly different and thus serve slightly different reliability goals. Requirement R8 requires the Transmission Operator to operate within an IROL. Requirement R11, however, requires the Transmission Operator to mitigate an exceedance if one has occurred. For example: If an exceedance occurs and goes away on its own within T_v, there is no violation of Requirement R8. However, if that exceedance occurs and the Transmission Operator doesn’t act to mitigate it within T_v then they are in violation of Requirement R11. No change made.
R6 (now Requirement R9) – IROL exceedances would be covered under Requirement R3 as they would represent an emergency condition. No change made.
VSLs and Measures have been revised as necessary.
</td></tr>
<tr><td>Southern Company</td><td>No</td><td>
The measure for R2 does not carry forth the definition of which other TOP should be informed. R2 requires informing other TOPs that are expected to be affected. The measurement requires that contact was made with all TOPs that were affected. The list of TOPs that are expected to be affected before the fact may be different than the list of TOPs that actually were affected.Would suggest minor change in R2 from “Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions” to “Transmission Operators known or expected to be affected of actual Emergency or anticipated Emergency conditions”
The second “each” in M1 and M4 should be deleted.
Would suggest modifying VSL for M5 to read in the same tense of the Measure. Specifically, instead of “The Transmission Operator did not operate within an identified” to “The Transmission Operator operated outside
</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		an identified”
Response: The SDT agrees that there is some confusion created by the wording of the requirement and has modified the requirement based on the comments by you and other respondents in an attempt to provide greater clarity. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. **M3**. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and all other Transmission Operators that it knew or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. The SDT agrees that the second each in M1 and M5 should be deleted and has modified the measures accordingly. **M1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, in accordance with Requirement R1, evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. **M5.** Each Transmission Operator shall make available upon request, evidence that operations it coordinated its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5 unless conditions did not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. While the proposed modification to Measure M6 is one way to write the VSL, the SDT does not see an issue with the way the VSL is currently modified and has left it unchanged.		
US Bureau of Reclamation	No	The proposed addition of the term 'by the Transmission Operator" makes the Transmission Operator the reliability entity the exclusive source for determining when operations are expected to have a known or expected reliability impact on other reliability entities. This would eliminate the Generator Operator's ability to determine which operations can have an impact on other reliability entities such as Transmission Operators.The response from the SDT clearly indicated that "further the SDT recognizes that the scope and number of individual agreements, which may be needed to ensure that all operations are fully coordinated for all operations known or expected to have a reliability impact upon other Reliability Entities is highly likely to vary greatly from region to region or organizational arrangement to organizational arrangement. If the Transmission Operator is to be the exlusive source for the determination of those operations have or are expected to have a reliability impact on other reliability entities, then a separate requirement and measure is needed to ensure that such a determination is properly conveyed to the Generator Operator. Prior to this addition, the Generator Operator was able to make the operational impact assessment. The SDT should

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>either create a new requirement for the TOP to provide to the Generator Operators the operations that have or are expected to have impacts on reliability entities or alter the language that the reliability entities determine when their respective operations impact other realiability entities.</td></tr>
<tr><td colspan="3">Response: The SDT agrees that the Generator Operator will not know of operations on the BES and has deleted the requirement.</td></tr>
<tr><td>Midwest ISO Standards Collaborators</td><td>No</td><td>We largely agree with the requirements but have a few suggestions.In R2 and R4, “expected to be affected” would include known. Please strike known.

R5 and R6 require the TOP to identify a sub-set of SOLs that may be larger than the IROL subset ahead of time and to notify the RC of what actions it is taking to return the system to within operating limits when they are exceeded. Why is there not a requirement to also operate within those SOLs and return within the SOL if exceeded?

The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages?

The measures for R5 and R8 need to be clear that these are event driven requirements and only evidence is required if an “event” has occurred.</td></tr>
<tr><td colspan="3">Response: The SDT feels that the term ‘known’ has a different connotation than ‘expected’ and therefore both are required. No change made.

The SDT determined that the Reliability Coordinator should be notified when the SOLs in Requirements R5 and R6 (now Requirements R8 & R9) are exceeded so that the assessor can be situationally aware and assess the need for additional action. At the same time, the SDT did not want to limit the operational flexibility of a Transmission Operator to temporarily exceed an SOL by a slight amount to avoid having to take drastic actions such as shedding load unnecessarily.   No change made.

The SDT has reviewed all of the VSLs based on the latest guidelines and made changes accordingly. The R10 VSL is an example of such changes.

<table>
<tr><td>R10 VSL</td><td>N/A</td><td>N/A</td><td>N/A</td><td>The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL has been exceeded</td></tr>
</table>

The SDT feels that the measures are clear as written and has not made a change.</td></tr>
<tr><td>WECC RC</td><td>No</td><td>What is definition for when an SOL supports or does not support Local Area Reliabilty?</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		Is this for 100kV and above? What are the timing requirements for returning elements to a level below their SOL?
Response: The SDT has changed Requirement R8 to clarify this issue. **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.** The Reliability Standards are for the BES which is 100 kV and above unless specific exceptions are noted in the Applicability Section. Timing requirements would be based on the specific SOL characteristic such as if it is based on a facility thermal rating.		
James A Maenner	Yes	
Lakeland Electric	Yes	
Salt River Project	Yes	
The Detroit Edison Company	Yes	
Response: Thank you for your response.		

2. TOP-002-3: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: Industry comments centered on requests for clarification from the SDT. The SDT has responded to these comments and made changes as noted below.

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.

R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.

Data retention - Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling 90 day period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	No	(1) We continue to disagree with the way R2 is worded. R1 requires a TOP to conduct next day analysis to assess if any of the SOLs will be exceeded. R2 requires that the TOP develop plans to preclude operating in excess of only the IROLs identified as a result of the assessment performed in R1. Given our stance on this issue and understanding that IROLs represent a subset of SOLs, we believe R2 should be changed to refer to SOLs. In our view, a TOP needs to conduct next day analysis to assess if any of the established limits will be exceeded, develop plans to preclude operating in excess of the IROLs and SOLs, and make resources and actions available for mitigating exceedances if and when they occur. Like operating within SOL sand IROLs, this is fundamental to reliable operation. We suggest R2 be revised to include all SOLs.
Response: In response to your comment and those of others, the SDT has made a change to Requirement R2 to include certain, qualified SOLs that have been identified as needed for local are reliability. **R2**. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Northeast Power Coordinating Council	No	(1) We continue to disagree with the way R2 is worded. R1 requires a TOP to conduct next day analysis to assess if any of the SOLs will be exceeded. R2 requires that the TOP develop plans to preclude operating in excess of only the IROLs identified as a result of the assessment performed in R1. Given our stance on this issue and understanding that IROLs represent a subset of SOLs, we believe R2 should be changed to SOL. In our view, a TOP needs to conduct next day analysis to assess if any of the established limits will be exceeded, develop plans to preclude operating in excess of the IROLs and SOLs, and make resources and actions available for mitigating exceedances if and when they occur. Like operating within SOLs and

Organization	Yes or No	Question 2 Comment
		IROLs, this is fundamental to reliable operation. We suggest R2 be revised to include all SOLs. (2) Remove “single” from R1.
Response: (1) In response to your comment and those of others, the SDT has made a change to Requirement R2 to include certain, qualified SOLs that have been identified as needed for local are reliability. **R2**. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. (2) The SDT disagrees with removing single from Requirement R1. By not including the word single, some may interpret this requirement to operate within all multiple Contingencies which is contrary to how the industry operates and what is necessary for reliability. However, the SDT has made a clarifying change to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		
Bonneville Power Administration	No	Comments: Change R1 wording. "R1:The wording is still incorrect in our interpretation. The wording needs to be changed to state that an assessment of the next days planned study conditions SOL'S is still valid with the expected next day’s conditions. The previous wording isn’t realistic because many days the assessment could determine a contingency response would cause the in place SOL to be exceeded. Some contingencies require the SOL to be lowered to prepare for the next condition which would cause real-time system readjustment. And the next contingency and the next contingency ?. Some days the assessment would say the SOL could be exceeded for HLH. The key to those SOL'S is that the SOL'S are set at a level where the worst contingency for that path would not cause the interconnection to go unstable, i.e. cascading outages.. Suggest clarifying what is meant by “their” in R3:”Each Transmission Operator shall notify all reliability entities identified in theplan(s) cited in Requirement R2 as to their role in the plan(s).” Perhaps state “their role in the TOP’s Plans”.
Response: The SDT believes Requirement R1 as drafted aligns with the interpretation for TOP-002-2a, Requirement R11. However, the SDT has made clarifying changes to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. ‘Their’ refers to the antecedent all reliability entities. The SDT finds no additional clarity from the proposed wording change. No change made.		
Platte River Power Authority Operations Group	No	Is "an assessment" consistent with the interpretation of TOP-002-2 R11 by Orlando Utilities Commission or are you requiring a real-time contingency analysis tool?We believe there should be no requirements for the TOP to have a real-time contingency analysis tool if the BA and RC have the tool and model the TOP's system.

Organization	Yes or No	Question 2 Comment
Response: The SDT has made clarifying changes to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		
Duke Energy	No	R1 , M1 and Data Retention could be interpreted to require that daily assessments (which could include a dated Power Flow) will have to be kept for 6 months. This could take up a lot of space. R2 as worded gives the impression that an IROL will be identified during a daily assessment respecting an SOL per R1. First, if you respect the SOL there will be no IROL. Second, simple day-ahead studies with an online Power Flow looking for contingencies might not identify an IROL. It might, but you would probably need to examine some multiple contingencies before something would cascade. R2 could be revised to read that each TOP shall plan to preclude operating in excess of any identified IROL's during the day-ahead assessment per R1. Also, maybe this requirement should be an RC requirement.
Response: The SDT agrees with your concern and has changed the data retention to 90 days. **Data retention** - Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling 90 day period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. R2. Requirement R2 requires an entity to compare SOLs/IROLs to flows and to identify any new SOLs/IROLs as needed. The SDT does not see that any additional clarity would be gained by the change of wording suggested for Requirement R2. No change made.		
WECC RC	No	R2 should include SOLs. In R3 the plan should be shared with the RC.
Response: The SDT believes SOL are local in nature and as such do not require a plan. When correctly identified, operating outside or exceeding a SOL will only harm the entity exceeding the SOL, not the Interconnection. R3. The Reliability Coordinator is a functional entity and is thus covered by the existing wording. No change made.		
IRC Standards Review Committee	No	Requirement #1: It is not clear why we introduce 'single' Contingency event since a TOP may be required to study multiple contingencies identified by its RC (See FAC-011-2, Requirement R3). A better term may be "Contineegency events identified in FAC-011."
Response: The SDT disagrees with removing single from Requirement R1. By not including the word single, some may interpret this requirement to operate within all multiple Contingencies which is contrary to how the industry operates and what is necessary for reliability. However, the SDT has made clarifying change to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		

Organization	Yes or No	Question 2 Comment
Salt River Project	No	
Response: Without specific comments, the SDT is unable to provide a response.		
Xcel Energy	Yes	R1- Is there a need to specify IROLs as well?
Response: IROLs are addressed in TOP-002-3, Requirement R2.		
Lakeland Electric	Yes	Requirement R-1 and Measure M-1 require modification for clarity. Replacing the undefined term “assessment” with the NERC defined term “Operational Planning Assessment” throughout the TOP-002-3 standard will help to clarify both line items. Using “Operational Planning Analysis” in measure M-1 clarifies that the power flow study does not have to be performed day-ahead (see the definition of Operational Planning Analysis). This is in-line with the recent interpretation issued by NERC discussed in the appendix of TOP-002-2a. Using “Operational Planning Analysis” in requirement R-1 ensures the planner understands that his or her assessment is meant to be more than just a determination of System Operating Limits. Requirement R-1 would also benefit from clarifying “single Contingency event.” Current day-ahead contingency analysis is limited to determining system performance during single transmission line, generator and transformer outages. However, using “single Contingency event” could include lightning struck towers with two or more transmission lines or even bus failures at which multiple transmission lines terminate. Unless it is the intent of the standard team to increase the scope of TOP-002 I recommend finishing requirement R-1 with “. . . involving transmission lines, transformers, and generators.”
Response: Operational Planning Assessment is not a currently defined term. The SDT believes that you meant ‘Operational Planning Analysis and agrees and has made the change. The SDT disagrees with removing single from Requirement R1. By not including the word single, some may interpret this requirement to operate within all multiple Contingencies which is contrary to how the industry operates and what is necessary for reliability. FAC-011-2 Requirement R3.3 already requires a Reliability Coordinator to determine SOLs from a list of multiple Contingencies that the Planning Coordinator identifies per FAC-014-2, Requirement R6 as having Stability limits. To remove the word single here would only cause confusion if additional multiple Contingencies over and above those used to identify SOLs in FAC-011-2, Requirement R3.3 are required to be tested. They are not required or needed for reliability. No change made in this regard. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		
Entergy Services, Inc	Yes	This standard seems to conflict with MOD-001, Requirement 7. This standard requires that: When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. When applying the requirements from TOP-002-3 along with the MOD-001 standard, it seems that all TSP’s will need to calculate ATC or AFC up to the calculated IROL for the time

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>period. When the two standards are looked at independently they are fine, when you look at both, there is some confusion on where NERC wants the TSP’s to go.</td></tr>
<tr><td colspan="3">Response: TOP-002-3 is not applicable to Transmission Service Providers and the SDT does not see any conflict. MOD-001, Requirement R7 requires AFC/ATC/TTC studies to use no more limiting assumptions than what is used in real-time studies, i.e., the Transmission Operator sets the limits and the Transmission Service Provider follows. No change made.</td></tr>
<tr><td>American Electric Power</td><td>Yes</td><td></td></tr>
<tr><td>American Transmission Organization</td><td>Yes</td><td></td></tr>
<tr><td>Ed Stein - self</td><td>Yes</td><td></td></tr>
<tr><td>Electric Market Policy</td><td>Yes</td><td></td></tr>
<tr><td>FirstEnergy</td><td>Yes</td><td></td></tr>
<tr><td>ITC Holdings</td><td>Yes</td><td></td></tr>
<tr><td>James A Maenner</td><td>Yes</td><td></td></tr>
<tr><td>Manitoba Hydro</td><td>Yes</td><td></td></tr>
<tr><td>Midwest ISO Standards Collaborators</td><td>Yes</td><td></td></tr>
<tr><td>SERC OC Standards Review Group</td><td>Yes</td><td></td></tr>
<tr><td>Southern Company</td><td>Yes</td><td></td></tr>
<tr><td>The Detroit Edison Company</td><td>Yes</td><td></td></tr>
<tr><td>US Bureau of Reclamation</td><td>Yes</td><td></td></tr>
</table>

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Subcommittee	Yes	N/A
Response: Thank you for your response.		

3. TOP-003-1: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: Due to industry comments, the following clarifying changes were made:

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

Part 1.1, last bullet: Operating parameters for equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.

Part 1.3 A periodicity for providing data.

Part 1.4 The deadline by which the respondent is to provide the indicated data.

R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. . The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled.

Organization	Yes or No	Question 3 Comment
WECC RC	No	Is mutually agreeable a formal process? Should it be in writing? The RC should be involved because of the numerous formats it has to deal with.
Response: The SDT used the phrase ‘mutually agreeable’ because it did not feel it would be necessary to have one format that fits all, nor do it feel it would be feasible to do so. The SDT feels that this phrasing allows the entities involved the flexibility they need to make this happen and therefore does not believe that the process needs to be formal or in writing but recognizes that entities are not prevented from doing so. The requirement is clear that the specification must be ‘documented.’ The Reliability Coordinator is not required to be directly involved. This requirement is focused on the Transmission Operator and Balancing Authority receiving the date they need to perform their function to meet the NERC reliability requirements. Any data that the Transmission Operator or Balancing Authority needs to collect because the Reliability Coordinator requires the data from them is likely to be included in this list. Reliability Coordinator requirements are covered in the IRO family of standards.		
SERC OC Standards Review Group	No	R1 Does “specification for data” mean a complete listing of data points or a listing of types of data required for different types of facilities such as “generation, transmission, etc.” Also, does this standard apply solely to internal requirements of a BA and its TOP? The concern is the multiple types of formats that may be required in order to exchange data with an expanded list of entities external to the BA or TOP.

Organization	Yes or No	Question 3 Comment
		M5 measurements should be modeled similar to the measurement in M4, in particular, that last sentence of M4. Is TOP-003-2 a new standard utilizing an existing number? If so, does the previous TOP-003-1, Planned Outage Coordination have to be retired? The migration from the current TOP-003-1 to the new TOP-003-2 seems like it could cause confusion. Would it be better to just retire TOP-003-1 and form a new standard number like TOP-011-1? R4 and R5: Should there be a time requirement for complying with a data request?
Response: The specification for data is intended to ensure the Transmission Operator and Balancing Authority have the data they need to complete their functional responsibilities. A complete listing of the data points or a listing of the types of data required would both seem to allow the Transmission Operator and Balancing Authority to specify the data they need to complete their function responsibilities. M5 measures**:** The SDT agrees with your suggestion and has modified Measure M5 as shown below. **M5.** Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. . The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled. TOP-003-1 will be retired as per the Implementation Plan filed for this project. The numbering scheme for standards is controlled by the NERC Standards Process Manager and is not in the scope of the SDT. R4 and R5: The data specification required by Requirement R1 includes, per part 1.3, a timeframe and periodicity of the data. To clarify this, the SDT has broken this out into 2 distinct parts. **Part 1.3** A periodicity for providing data. **Part 1.4** The deadline by which the respondent is to provide the indicated data.		
Southern Company	No	R1 is written for the Operations Planning timeframe. As such, would suggest rewording “shall have a documented specification for data necessary for Real-time monitoring and reliability assessments” to “shall have a documented specification for data necessary for reliability assessments and Real-time monitoring”. Having “Real-time monitoring” mentioned first may convey the impression that “Real-time” also applies to the reliability assessments. Also, would suggest rewording “Equipment at voltage levels lower than” to “Outages of equipment at voltage levels lower than.”
Response: The SDT has made clarifying changes to the wording of the requirement. **R1**. Each Transmission Operator and Balancing Authority shall have a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.		

Organization	Yes or No	Question 3 Comment
The SDT has clarified the wording for this part in response to your comment. **Part 1.1, last bullet**: Operating parameters for equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.		
Xcel Energy	No	R5- We are concerned that this may be liberally applied to require entities to provide data to other entities with no clear reliability need. We feel this requirement could place extreme and unnecessary burden on entities to provide data in a specified format and time interval.
Response: The SDT believes that the requirement is reasonable in that requests must fall within the parameters of the data specifications provided by each entity. No change made**.**		
Bonneville Power Administration	No	Regarding M4 (last sentence): “The evidence shall be that there are noTransmission Operators as identified in Requirement R2 or Balancing Authorities asidentified in Requirement R3 with outstanding requests for data to the subject entitythat have been unfilled”.This doesn't mention the "TIMEFRAME" response time to provide data after a request is made. (i.e. 30 days, 60 days or whatever the reasonable "TIMEFRAME" is to modify databases or communication channels.) The VSL should be adjusted accordingly. If an entity has just received a request and is being audited the next week before fulfilling the request that would be a SEVERE VSL, which seems inappropriate.
Response: The SDT has clarified Parts 1.3 and 1.4 to address your concerns. **Part 1.3** A periodicity for providing data. **Part 1.4** The deadline by which the respondent is to provide the indicated data.		
Duke Energy	No	The data specification in R1 is broad and could force a company to name every breaker, voltage point, MW point, etc. on their system. Perhaps an ICCP document or something similar could be used, but it’s not clear as the requirement is currently written. Also, this standard goes into a lot of detail in R1 through R4. This standard could be simply one requirement, R5.
Response: The specification for data is intended to ensure the Transmission Operator and Balancing Authority have the data they need to complete their functional responsibilities. A complete listing of the data points or a listing of the types of data required would both seem to allow the Transmission Operator and Balancing Authority to specify the data they need to complete their function responsibilities. The SDT believes that the requirements, as written, are correct and lend themselves more readily to measurement.		
US Bureau of Reclamation	No	The modification of the language related to data specifications creates a potential for compliance violation for the

Organization	Yes or No	Question 3 Comment
		reliaibility entities other than the Transmission Operator. The specifications for data " necessary for Real-time monitoring and reliability assessments" needs to be more expicit. The language allows it to be below the BES voltage threshold. This is coupled with the requirement that no outstanding requests for rata from the transmission operator are unfilled. This double negative is easier to restate that all data requests from the transmission operator must be filled. This is very open ended. Should the data request is unreasonable, the other reliability entities would be non-compliant. The data specification need to be subject to review and approval by the Reliability Coordinator in the case of conflict brought by the reliabilty entity. The requirement, in case of conflict, would not be invoked until the data specifications are approved. This opportunity for appeal of the specifications ensures transmission operators apply technical reasoning in developing the specifications.
Response: The SDT disagrees with your assessment. Part 1.3 has been changed and Part 1,4 added to address your concern. Part 1.2 requires a mutually agreeable format. Requirement R4 requires the entities receiving the data specification to provide it in a format that they agreed upon which includes the timeframe. **Part 1.3** A periodicity for providing data. **Part 1.4** The deadline by which the respondent is to provide the indicated data.		
MRO NERC Standards Review Subcommittee	No	The term "Long term outages" in the first sub bullet is not clear, please clarify.
American Electric Power	Yes	AEP would appreciate that the reference to "Long term outages" in R1.1.1. be specified in terms of the time elapsed.
Response: The Transmission Operator and Balancing Authority will have to define what long term outages are in their data specification. They could be different for various Transmission Operators and Balancing Authorities so no set time frame can be selected. No change made.		
Northeast Power Coordinating Council	Yes	Regarding R4, M4, it does not appear to be warranted that a Generator Owner, Generator Operator, Interchange Authority, or Load-Serving Entity provide evidence that there are no outstanding requests for data. As the originator of the request, the evidence that there are no outstanding requests for data should be provided by the Balancing Authority or Transmission Operator, as applicable.
Response: The SDT is addressing the need to show evidence without introducing the need to "prove a negative". If no outstanding request for data can be found, then compliance exists. If there has indeed been a request, but the entity has not provided the data, the requester will likely provide a complaint and a copy of the request. An attestation that all requests have been fulfilled may suffice. No change made**.**		
FirstEnergy	Yes	We agree with the changes to TOP-003-1. However, we feel that R3 should be re-written to be consistent with the wording in R2. We suggest a change as follows: "R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide

Organization	Yes or No	Question 3 Comment
		Facility status to the Balancing Authority."
Response: The SDT agrees with your suggestion and has changed the Requirement R3 wording to be consistent with the sequence contained in Requirement R2. **R3**. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.		
American Transmission Organization	Yes	
Ed Stein - self	Yes	
Electric Market Policy	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
ITC Holdings	Yes	
James A Maenner	Yes	
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
Salt River Project	Yes	
The Detroit Edison Company	Yes	
Response: Thank you for your response.		

4. **TOP-004-3: Do you agree with the decision to move the lone remaining requirement of this standard to TOP-001-2? If not, please supply specific reasons why you do not agree with this move.**

Summary Consideration: All respondents agreed with this change.

Organization	Yes or No	Question 4 Comment
American Electric Power	Yes	
American Transmission Organization	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Ed Stein - self	Yes	
Electric Market Policy	Yes	
FirstEnergy	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
ITC Holdings	Yes	
James A Maenner	Yes	
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 4 Comment
Council		
Platte River Power Authority Operations Group	Yes	
Salt River Project	Yes	
SERC OC Standards Review Group	Yes	
Southern Company	Yes	
The Detroit Edison Company	Yes	
US Bureau of Reclamation	Yes	
WECC RC	Yes	
Xcel Energy	Yes	
NERC Standards Review Subcommittee	Yes	N/A
Response: Thank you for your response.		

5. TOP-001-2, Requirement R1: Do you believe that the Balancing Authority issues Reliability Directives directly for transmission-related limits and therefore should be in the TOP standards,(vote YES); or do you believe that the Balancing Authority in its role as a Balancing Authority issues Reliability Directives to balance load and generation and only indirectly affects transmission flows (recognizing that an entity that serves as both a Transmission Operator and a Balancing Authority would be covered under the Transmission Operator requirement) (Vote NO). Please be as specific as possible with your reply.

Summary Consideration: The overwhelming majority of respondents 'voted' No to this question which validates the position of the SDT. Thus, no changes were necessary.

Organization	Yes or No	Question 5 Comment
SERC OC Standards Review Group		We are unsure how to respond to this question as it pertains to TOP-001-2, R1.
Electric Market Policy	No	
Xcel Energy	No	
ITC Holdings	No	Balancing Authorities do not operate transmission. They would only issue requirements with regard to capacity and energy emergencies.
Midwest ISO Standards Collaborators	No	Balancing Authorities do not operate transmission. They would only issue requirements with regard to capacity and energy emergencies.
James A Maenner	No	BAs that neither own nor operate transmission should not issue reliability directives for transmission-related limits. Without the tools and knowledge of a Transmission Operator, the BA could isssue conflicting orders to the TOP's operating plans. Certainly, the BA should relay a TOP directive but not be the initiator.
Manitoba Hydro	No	The BA is responsible to operate its generation assets within the reliability constraints established by the Transmission Operator and Reliability Coordinator.
Independent Electricity System Operator	No	The BA's role is to balance load-generation-interchange and does not have any direct role in monitoring and operating system conditions within transmission-related limits.
Northeast Power Coordinating Council	No	The BA's role is to balance load-generation-interchange and does not have any direct role in monitoring and operating system conditions within transmission-related limits.

Organization	Yes or No	Question 5 Comment
IRC Standards Review Committee	No	The BA's role is to balance load-generation-interchange only; it does not have any direct role in monitoring and operating system conditions within transmission-related limits.
Platte River Power Authority Operations Group	No	The Transmission Operator issues the "Transmission" reliability directive and the Balancing Authority issues directives to balance the generation to load.
Bonneville Power Administration	No	Transmission-related issues are the responsibility of the TOP not the BA.
The Detroit Edison Company	No	We believe that the Balancing Authority in its role as a Balancing Authority issues Reliability Directives to balance load and generation and only indirectly affects transmission flows and should not be in the TOP standards.
WECC RC	No	In WECC, the RC deals mainly with the BAs. The BAs with their responsibility to maintain load and resources, ACE, and frequency places them in a position to direct and control all other activities on the interconnection. The RC expects the BAs to accomplish and direct actions to restore or mitigate contingencies in the interconnection.
Southern Company	No	TOP-001-2 does not mention any entity except for the Transmission Operator as issuing Reliability Directives.Yes, it is appropriate for the Balancing Authority to issue Reliability Directives that are related to his responsibilities (issues regarding balance load and generation), but there should be no confusion that the Reliability Coordinator has ultimate authority and thus could issues overriding Reliability Directives. The definition of a Balancing Authority in the NERC Glossary is, "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." This definition gives them no responsibility for transmission limits. However, the Balancing Authority does need to be able to give Reliability Directives in order to aid in the resolution of transmission-related limit problems.
We Energies	No	We Energies joined MISO's comments for this project. We have one additional comment for this question. The BA may need to issue Directives to Generator Operators or Distribution Providers in response to a TOP or RC need to resolve a transmission issue. Basically "pass-through" the Directive from the TOP or RC to the entity that will actually carry out the directed action.
Response: Thank you for your response.		
American Transmission Organization	No	Because the team is use the term Reliability Directive our answer may depend on what how this term is finally defined. We believe that the term needs to be defined and approved by skateholders prior to this standard being posted for balloting.

Organization	Yes or No	Question 5 Comment
US Bureau of Reclamation	No	The term "Reliability Directive is not a defined term. The question is poorly worded since the TOP-001-2 R1 specifically reserves the reliability directive to Tranmission Operator for this standard. The Balancing Authority does not issue directives. It works within its capacity and emergency plan to aleviate imbalances. After implementing all of its remedies the Balancing authority works through the reliability coordinator. The Reliability Coordinator may declare an emergency and take specific actions. See the refercences below:EOP 002 - R2. Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.R5. . The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.R6 If the Balancing Authority cannot comply with the Control Performance andDisturbance Control Standards, then it shall immediately implement remedies to do so.These remedies include, but are not limited to:R6.1. Loading all available generating capacity.R6.2. Deploying all available operating reserve.R6.3. Interrupting interruptible load and exports.R6.4. Requesting emergency assistance from other Balancing Authorities.R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:R7.1. Manually shed firm load without delay to return its ACE to zero; andR7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.”R8. A Reliability Coordinator that has any Balancing Authority within its ReliabilityCoordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
NERC Standards Review Subcommittee	No	The MRO NSRS believes any directives that a BA may issue should be in the BAL standards. R1, states that a BA, DP, LSE, and GOP shall comply with a Reliability Directive issued by a TOP. Reliability Directive is not defined by NERC. A definition has not been proposed.
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry. **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		
American Electric Power	Yes	Even in conditions where the BA is providing RDs to balance load and generation, the changes may still impact the BES. Under such circumstances, there remains a need for the BA to be aware of loadings on the BES.

Organization	Yes or No	Question 5 Comment
Duke Energy	Yes	The BA is involved in generation dispatch, which directly affects transmission flows.
Response: The Balancing Authority does not directly originate Directives to alleviate Transmission issues. They only respond to what they are told by the Reliability Coordinator or Transmission Operator. The majority of commenters agree with this position. No change made.		
FirstEnergy	Yes	The question as written is confusing based on the present wording of TOP-001-2 R1. Nevertheless, we believe that the Balancing Authority (BA) should be applicable in the TOP-001-2 standard and that their role as stated in R1 is correct. The BA receives direction from the TOP when redispatch solutions are needed to alleviate transmission-related limits (i.e. voltage, thermal, etc).
Ed Stein - self	Yes	
Lakeland Electric	Yes	
Response: Thank you for your response.		

6. Do you agree that with the changes in the 3rd posting that this project is ready to go to ballot? If not, please supply specific reasons why not.

Summary Consideration: No changes were made to requirements as a result of the comments received to this question. However, due to the number of comments received requesting an additional posting, and the number of changes made to the revised standards, the SDT agrees that an additional posting is required.

Organization	Yes or No	Question 6 Comment
Southern Company		Additional clarification per our previous comments is required. Re-posting may not be required.
Ed Stein - self	No	Due to my earlier response
Electric Market Policy	No	See comments above
WECC RC	No	See previous comments.
SERC OC Standards Review Group	No	See the above comments.Note: The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
ITC Holdings	No	The comments on TOP-001-2, particularly in regard to R6, need to be resolved before balloting.
Response: Please see the responses to previous comments.		
IRC Standards Review Committee	No	(1) The SRC is concerned that the absence of an explicit requirement for operating within SOLs may be problematic. Operating within SOLs is an important operating practice that will position the system to be stable within the acceptable reliability criteria included in the definition of SOLs and the requirements to be included in the methodology that is used to determine SOLs.The SRC recognizes that SOLs cover the full range from minor localized limits through Interconnection Operating Reliability Limits (IROLs), and that SOLs are defined to respect the facility and equipment ratings that are included in the determination of the values of SOLs. The suggested requirement R6 in TOP-001-2 for a TOP to identify SOLs, for which the TOP is to notify the RC when the SOLs are exceeded, is intended to address those SOLs that, while not meeting the definition of IROLs, may have potential impact that is important from a local viewpoint. Although these SOLs may not cause an impact equivalent to or greater than that in the definition of Adverse Reliability Impact, they deserve additional attention, including monitoring and notifications between TOPs and RCs. If the SDT holds the view that operating within the identified SOLs and correcting their exceedances are implicit and precursory to R7 and R8, then we would

Organization	Yes or No	Question 6 Comment
		suggest to make it explicit by revising R5, by saying, for example: R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL Tv, and each System Operating Limit (SOL) as identified in R6 and its associated time period as determined by the TOP. Similar to their IROL counterparts, operating within SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations, although for IROLs the interconnected system impact is readily obvious compared to the SOLs. The same principle holds true for day-ahead operational planning so that the needed control measures can be identified and made available in advance to prevent operating in excess of SOLs and to mitigate exceedances if and when they occur during day at hand and real-time operations. To this end, we suggest the SDT consider revising R2 of TOP-002-3 to: "Each Transmission Operator shall plan to preclude operating in excess of those System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) identified as a result of the assessment performed in Requirement R1." (2) Also there is concern that a definition for Reliability Directive has not been determined and agreed upon through the standards development process. Until such time that the definition of Reliability Directive can be developed and agreed to, the references to Reliability Directives or these standards should not go to ballot.
Response: The SDT agrees that operating within a certain subset of SOLs such as IROLs is fundamental to reliability and has made changes throughout TOP-001-2 and TOP-002-3 accordingly. (2) Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry. **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		
NERC Standards Review Subcommittee	No	A. A Reliability Directive must be defined and there must be an opportunity to comment before balloting can begin. B. Our responses to the previous questions are additional reasons why this standard should not go to ballot and that this standard needs another comment period.
Response: A. Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry. **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency. B. The SDT agrees that one more draft and posting is necessary.		

Organization	Yes or No	Question 6 Comment
American Electric Power	No	AEP believes that one more draft is needed to verify that key edits provided by stakeholders during this round are included before proceeding to ballot.
Response: The SDT agrees that one more posting is necessary..		
Manitoba Hydro	No	Changes are still required to TOP-001-2
Response: The SDT has made changes to TOP-001-2 and agrees that one more posting is necessary.		
American Transmission Organization	No	Changes needed to remove R6 from draft TOP-001-2 and to include a requirement to establish TV for all IROL's.
Response: Requirement R6 (now Requirement R8) was added in response to substantial industry comments received in the second posting and remains in the proposed standard. FAC-014-2, Requirement R5.1.2 requires the Reliability Coordinator to identify the IROL T_v. No change made.		
Bonneville Power Administration	No	Correct R1 to assess the SOL is proper, not that the SOL could be exceeded. Where does the seasonal planning operations coordination described in TOP-002-2 R3 go? Re: the MOD-001-1 proposal.
Response: The SDT does not understand the comment nor is it able to see a correspondence to any of the Requirement R1's. Without a definitive reference, the SDT is unable to respond to your comment. The new TOP-003-2, Requirement R1 addresses all time frames, including seasonal planning operations coordination.		
Platte River Power Authority Operations Group	No	Terms need to be defined and clarificaiton needs to be added.
Duke Energy	No	We believe that more clarity is needed on the requirements in these standards before going to ballot.
Response: The SDT has clarified requirements, defined terms and agrees that one more draft and posting is necessary.		
US Bureau of Reclamation	No	The two outstanding issues related to the new language proposed by the SDT need to be resolved first.TOP 001 needs to be modified to either recognize that the GOP can determine which operations can impact other reliability entities or insert a new requirement that the TOP must develop and provide to the GOP the operations that may impact other reliability entities.

Organization	Yes or No	Question 6 Comment
		TOP 003 needs to be modified to either place specific limitations on the data specifications developed by the TOP or that the Reliability Coordinator must approve data specification developed by the TOP when they are disputed by the reliability entity which must satisfy the obligations such data specifications impose on them.
Response: The SDT agrees that the Generator Operator will not know of operations on the BES and has deleted the requirement. The SDT has changes Part 1.3 and added Part 1.4 to address these concerns. Part 1.2 requires a mutually agreeable format. Requirement R4 requires the entities receiving the data specification to provide it in a format that they agreed upon which includes the timeframe.		
Independent Electricity System Operator	No	We continue to strongly disagree with removing the requirements for a TOP to plan and make day ahead arrangement for operating with all SOLs, and during day at hand and real time operate the system within established SOLs (and IROLs) and mitigate SOL exceedances within a predetermined time period. These are the most critical tasks for the TOPs, and are fundamental to ensuring reliability. We are unable to support these standards if the necessary requirements are not reinstated/revised (as suggested in Q1 to change R5 of TOP-001 and in Q2 to change R2 of TOP-002). Finally, we recommend changing “local” in R6 to “Transmission Operator” to avoid creating ambiguity regarding what is referred to in the requirement.
Response: The SDT has made numerous changes to TOP-001-2 and TOP-002-3 to include the concept of local reliability SOLs. In Requirement R6 (now Requirement R8) “local” was intended to clarify that these SOLs, while important, did not affect bulk power system reliability. The SDT continues to believe that the use of the word “local” conveys the intent better than the term “Transmission Operator” would.		
Northeast Power Coordinating Council	No	We continue to strongly disagree with removing the requirements for a TOP to plan and make day ahead arrangement for operating with all SOLs, and during day at hand and real time operate the system within established SOLs (and IROLs) and mitigate SOL exceedances within a predetermined time period. These are the most critical tasks for the TOPs, and are fundamental to ensuring reliability. We are unable to support these standards if the necessary requirements are not reinstated/revised (as suggested in Q1 to change R5 of TOP-001 and in Q2 to change R1 and R2 of TOP-002). R6 should be reworded to read "Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs)which, while not IROLs, support its Transmission Operator area reliability.
Response: The SDT has made numerous changes to TOP-001-2 and TOP-002-3 to include the concept of local reliability SOLs.		
Xcel Energy	No	We feel several modifications are needed before this is ready to ballot, as detailed in our previous responses. Also, the SDT indicates that changes in this project are dependent upon changes in Project 2006-06. Final drafts of those standards are not complete and it is not clear from a mapping perspective as to how some of the

Organization	Yes or No	Question 6 Comment
		requirements originally in TOP are now covered under those standards.
FirstEnergy	No	We feel that the current draft still has issues to be addressed before balloting begins (see our comments on Questions 1 through 5). Also, we provide the following additional comments:1. The mapping of all the requirements and standards associated with this project provided within the Implementation Plan during the first posting is a valuable tool for industry personnel in charge of tracking compliance. However, this mapping matrix now appears to be removed from the implementation plan. We feel that the team and/or NERC should provide a revised mapping document during the next posting of documents for this project so that industry can review it. Then it should be retained as a reference tool for industry when transitioning their compliance documentation from the current standards to the new standards. 2. The implementation plan currently states: "The assumption used by the SDT in establishing this Implementation Plan is that the project mentioned in the prerequisites: Project 2006-06, Reliability Coordination; has been approved prior to the implementation of this Project 2007-03, Real-Time Operations." It should be clear that the implementation clock for these Real-Time Operations standards starts only after "applicable regulatory approval" of the standards associated with Project 2006-06.
Response: The SDT agrees that one more posting is necessary. The mapping matrix, which clearly identifies the linkages to Project 2006-06, has undergone substantial revision and will be provided with the next posting. The current plan of the SDT for this project is to submit it for approval simultaneously with Project 2006-06, Reliability Coordination.		
James A Maenner	Yes	
Lakeland Electric	Yes	
Midwest ISO Standards Collaborators	Yes	
Salt River Project	Yes	
The Detroit Edison Company	Yes	
Response: Thank you for your response.		

Consideration of Comments on Real-Time Operations — Project 2007-03

The Real-Time Operations SAR Drafting Team thanks all commenters who submitted comments on the 4th draft of the standards for Real-Time Operations – Project 2007-03. These standards were posted for a 30-day public comment period from August 4, 2010 through September 3, 2010. Stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 34 sets of comments, including comments from more 34 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

The SDT made a number of changes to requirements and measures based on industry comments and additional changes based on observations of a Quality Review team. Where a changes was made to a requirement, conforming changes were made to the associated measure and VSLs.

TOP-001-2:

- Requirement R2– added the word 'identified' to make it clear that it is only "identified Reliability Directives" included in the scope of the requirement. Added "Operations Planning" as an additional possible time horizon.
- Requirement R3 – changed 'of' to 'by' to correct a typographical error.
- Requirement R5 – changed 'coordinate' to 'inform;' changed 'coordination' to 'communications;' and replaced 'with those Transmission Operators' with 'those respective' for simplification.
- Requirement R6 – changed 'coordination' to 'notify;' added a phrase to be more specific about what functional entity to notify; changed 'telemetering' to 'telemetry' for clarity.
- Requirement R8 – changed 'local' to 'internal' to clarify that the scope is limited to the TOP's own area.
- Requirement R9 – changed the VRF from "high" to "medium."
- Requirement R11 – added a 30 minute constraint on the time to respond to an SOL supporting the TOP's internal reliability.
- Deleted Requirements R12 – R14 as these requirements related to facility capabilities and will now be addressed in a separate project. (Project 2009-02 Real-time Monitoring and Analysis Capabilities
- Added an explanation to justify the VSLs for R5.

TOP-002-3:

- Purpose – updated to more closely align with the requirements in the standard
- Updated the text box associated with Requirement R1 to clarify the expectation that the Operational Planning Analysis is required under all conditions.
- Requirement R2 - changed 'local' to 'internal' to clarify that the scope is limited to the TOP's own area.
- Requirement R3 – changed 'reliability' entity to 'registered entity' for additional clarity.
- Added an explanation to justify the VSLs for R3.

TOP-003-2:

- Requirement R1 – changed 'have' to 'create' for clarity; changed 'equipment' to 'facilities;' removed the language specifying that the outage information comes from the Transmission Operator or Balancing Authority.
- Requirement R4 – added the Transmission Operator as one of the entities that must provide requested data.
- Requirement R5 – merged into Requirement R4.
- Measures M2 and M3 – added web postings with acknowledgment as additional examples of acceptable evidence.
- Eliminated redundancies in VSLs for R2.

The SDT recommends that this project be moved forward to the balloting stage.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 315-439-1390 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X
2.	Group	Kenneth D. Brown	Public Service Enterprise Group Companies	X		X		X	X				
3.	Group	Brent.Ingebrigtson@eon-us.com	E.ON U.S.	X		X		X	X				
4.	Group	Marie Knox	Midwest ISO Standards Collaborators	X									
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
6.	Group	Sandra Shaffer	PacifiCorp	X		X		X					
7.	Group	Mike Hardy	SERC OC Standards Review Group	X		X		X					
8.	Group	JT Wood	Southern Company Transmission	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
10.	Group	Louis Slade, Jr.	Dominion	X		X		X	X				
11.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
12.	Group	Patrick Brown	PJM		X								
13.	Group	Ben Li	IRC Standards Review Committee		X								
14.	Group	Steve Rueckert	Western Electricity Coordinating Council										X
15.	Individuals	L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson			X								
16.	Individual	Dan Rochester			X								
17.	Individual	Joylyn Faust				X	X	X					
18.	Individual	John Fish						X					
19.	Individual	Jonathan Appelbaum		X									
20.	Individual	Kasia Mihalchuk		X		X		X	X				
21.	Individual	Jon Kapitz		X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Howard Rulf				X	X	X					
23.	Individual	RoLynda Shumpert		X		X		X	X				
24.	Individual	Greg Rowland		X		X		X	X				
25.	Individual	Michael Lombardi		X		X		X					
26.	Individual	Leland McMillan		X		X		X					
27.	Individual	Richard Kafka		X		X		X	X				
28.	Individual	Saurabh Saksena		X		X							
29.	Individual	Randi Woodward		X									
30.	Individual	Darryl Curtis		X									
31.	Individual	Catherine Koch		X									
32.	Individual	Terry Harbour		X									
33.	Individual	Jason Shaver		X									
34.	Individual	Michael Gammon		X		X		X	X				

1. TOP-001-2: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: As shown below, the SDT made a number of changes to requirements based on industry comments. All changes were semantic to provide additional clarity.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

R5. Each Transmission Operator ~~and Generator Operator~~ shall ~~coordinate~~ inform other Transmission Operators of its ~~respective~~ operations known or expected ~~by the Transmission Operator~~ to ~~have~~result in ~~a reliability impact~~ an Adverse Reliability Impact on ~~the portion of the BES of other~~ those respective ~~reliability entities~~Transmission Operator Areas with those ~~entities~~ Transmission Operators unless conditions do not permit such ~~coordination~~communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load,

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 within 30 minutes.

M5. Each Transmission Operator shall make available upon request, evidence that ~~operations~~ it ~~coordinated~~ informed other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas ~~with those Transmission Operators~~ in accordance with Requirement R5 unless conditions did not permit such ~~coordination~~ communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M8. Each Transmission Operator shall make available evidence that it has informed it~~'~~s Reliability Coordinator of each SOL~~s~~ which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
Public Service Enterprise Group Companies	No	In R1 the word "identified" was added as an adjective to describe "Reliability Directive." While this is a step in the right direction, it needs further clarification. The requirement should be further modified to indicate that the Transmission Operator must indentify. i.e., state that "this is Reliability Directive" to ensure that the entities that must comply with this requirement know that what is being communicated by the TOP is a Reliability Directive and not some other less urgent communication.
Response: "Reliability Directive" is not meant to equate to the urgency of a situation; rather it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views a Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to affect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made.		
E.ON U.S.	No	E.ON U.S. suggests that in the definition of directive the adjective "mandated" should be added and placed in front of "action."
Response: Revision to the definition is not in the scope of this standard. The Definition of Terms for TOP-001-2 states the "…definition (of Reliability Directive) is included here for ease of reference…" and that the Reliability Coordination SDT (Project 2006-06) is writing the definition and will post that definition for vetting by the Industry. The SDT would note that Requirement R1 states that entities "shall comply" with identified Reliability Directives. Thus, by identifying the action as a Reliability Directive, the requirement is mandating the action. No change made.		
Midwest ISO Standards Collaborators	No	Requirement #1 Comments cannot be developed for this requirement until we are able to see a final draft of the definition of Reliability Directive. It will have a significant impact on this requirement. Requirement #9 SOL's have not been defined clearly enough to require an identified time limit for exceedance. These durations could be set by the Transmission Owners or Operators based on the type of equipment, not dictated in the standard. Requirement #10 It is not clear when the RC should be informed, before, during or after actions have been taken to correct an overload. This needs to be discussed. Depending on the urgency of the situation, it may not be appropriate for the TOP to inform the RC prior to taking actions. It should simply be a requirement for the TOP to log or record actions taken for future review. Requirement #13 It is not clear what TOP area needs to be monitored. Language needs to be added to clearly state that a TOP should have access to information on other TOP areas that could impact the local area.
Response: Requirement 1 - The SDT understands the perspective for the Requirement R1 comment, however, as pointed out in the Definition of Terms for TOP-		

Organization	Yes or No	Question 1 Comment
001-2, the "…definition (of Reliability Directive) is included here for ease of reference…" and the Reliability Coordination SDT (Project 2006-06) is writing the definition and will post that definition for vetting by the Industry. The SDT drafted the words such that the definition is secondary to the requirement. As written, the Transmission Operator would only "identify" an action as a Reliability Directive when the Transmission Operator "needs" an additional incentive to cut off discussion about whether or not the requested entity should carry out the action. If the entity carries out the action without the Transmission Operator identifying the action as a Reliability Directive, then the definition is not important. If the entity is not carrying out the requested action, then by identifying the requested action as a Reliability Directive, then the entity must comply – and again the definition is not critical to the requirement. Requirement R1 is designed to make clear that any request designated as a Reliability Directive must be carried out as stated (and repeated back). The definition only restricts the Transmission Operator in that the request must be necessary "to address an emergency." That allows the Transmission Operator to issue a Reliability Directive to respond to an Emergency and also during normal times, if needed, to preclude an Emergency condition from arising. Requirement 9 - The 30 minute limit is generally recognized as a time related to the risk of a second event occurring; thus 30 minutes is the maximum time. That does not preclude an operator from choosing a shorter duration (lesser restriction – e.g., higher MW) limit and using a shorter duration. No change made. Requirement 10 - The requirement does define an explicit time. It is the time after an action was taken ("…inform … of its actions…") and after the limit was exceeded ("…to return…when an IROL …has been exceeded…"). The communication therefore is not mandated prior to the action being taken. The fact that the communications are about "all of its actions" precludes communications "during" the action; thus leaving the communications to the post-action time period. No change made. Requirement 13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Bonneville Power Administration	No	R5 - should refer to adjacent Transmission Operators. R8 - This daily documentation is burdensome. Reporting "all" SOL's to RC ahead of time as part of daily assessment in addition to the daily planned outage heads-up reporting. Suggest clarifying SOL as intended to be path loading limits and/or local area transmission service support limits, (the BES is a big system with lots of ratings, it can also mean voltage limits in addition to line and path limits). If there is a significant change to a limit, that would be important. R10 - Prefer having the RC call the TOP in 5 Minutes to ensure entity is aware of and acting on a limit excursion , rather than TOP interrupt system response to call RC to tell them the Operator is mitigating a SOL violation which is a already a NERC TOP standard to take immediate action. There's a typo in M12, M13, M14 when it refers to the wrong requirement due to renumbering R11 instead of R12, R12 vs. R13, and R13 vs. R14).
Response: Requirement 5 - The requirement limits the coordination to those Transmission Operators that the former Transmission Operator "knows" are impacted. If a Transmission Operator "knows" it will impact a non-adjacent Transmission Operator, then that fact should be communicated per this requirement. The requirement does not mandate direct communication – it can be handled through third party Transmission Operators – but it must be communicated. No		

Organization	Yes or No	Question 1 Comment
change made. <u>Requirement 8 -</u> The requirement does not specify “daily”. The reference to “significant change to a limit” must be defined by BPA before the SDT can address the comment further. No change made. <u>Requirement 10 -</u> The requirement does define an explicit time. It is the time after an act was taken (“…inform … of its actions…”) and after the limit was exceeded (“…to return…when an IROL …has been exceeded…”). The communication therefore is not mandated prior to the action being taken. The fact that the communications is about all of its actions precludes communications “during” the action; thus leaving the communications to the post action time period. No change made. The SDT did not see a need to be prescriptive about the reporting time. The proper phrase would be “as soon as time permits” but that phrase does not provide the clarity that compliance enforcers desire. No change made. The SDT corrected the typos in the Measures.		
SERC OC Standards Review Group	No	In R2, it appears that an entity might be faced with double jeopardy if it fails to notify the entity issuing the directive. Doesn’t R1 also include this same requirement? In R3, the phrase “affected of actual’ should be “affected by actual”. In R8 and M8, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”. In R12 and R13, it doesn’t seem possible to measure “monitoring”. These also seem like requirements that are ideally suited for the certification process. It appears that the numbering of the requirements within each measure may have gotten out of synch due to a cut and paste insert. In M8, SOLs should be singular. The data retention periods are too long and do not appear to serve the purpose of improving reliability. Specifically, the three (3) year retention period for SOL and IROL violations is two (2) years too long.
<u>Response:</u> <u>Requirements 1 & 2 -</u> Requirement R1 is written to address a priori prohibitions. This would be communicated at the time the actions were first being communicated. Requirement R2 is written to address conditions that arise after the entity agreed to do the action but found out later that conditions preclude such actions. No change made. <u>Requirement 3 -</u> Requirement was revised as requested. **R3.** Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ <u>by</u> actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. <u>Requirement 8 -</u> Local area reliability is not a defined term but rather (as stated in the requirement) it is “based on its (the Transmission Operator’s own)		

Organization	Yes or No	Question 1 Comment
assessment." The industry has debated this issue for a long time. This standard is written to ensure BES reliability by defining IROLs and to supporting individual Transmission Operators parochial definitions. The loss of a capital city in a state may have no impact at all on the BES, but politically that city is critical (think Washington, DC). Requirement R8 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). No change made. Requirements 12 & 13 – These requirements have been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT revised the Measures for the editorial errors as noted.. An entity need only keep the exception cases where actual violations have occurred, which should be a minimal amount of data. No change made.		
Southern Company Transmission	No	Southern's comments: Suggest modifying R3 language for additional clarity. Suggested alternatives might be "Each Transmission Operator shall inform its Reliability Coordinator of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis, and shall likewise inform any other Transmission Operators that are known or expected to be affected by those Emergencies" or "Each Transmission Operator shall inform its Reliability Coordinator and all other expectedly affected Transmission Operators of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis." In the first sentence of M5, the first usage of the word "operations" is redundant and can be struck. In R8, it is unclear what should be the treatment of SOLs that develop due to unanticipated system conditions that are not included in the Operation Planning analysis (i.e., real time system conditions deteriorate due to several unplanned outages). In R11, need to add "...within 30 minutes" after SOL. R14 can be mis-read to mean that the Transmission Operator grants approvals of outages, as opposed to granting the authority to grant approval to the System Operator. Also, it would be useful to clarify if the TOP still has the authority to also veto planned outages, in addition to the System Operator having that authority. M11 - M14 have references to incorrect Requirement numbers. In M8 and M14, the word "its" was incorrectly modified to "it's." SERC's comments: Southern participated in developing these comments and support them In R2, it appears that an entity might be faced with double jeopardy if it fails to notify the entity issuing the directive. Doesn't R1 also include this same requirement?

Organization	Yes or No	Question 1 Comment
		In R3, the phrase "affected of actual' should be "affected by actual". In R8 and M8, what is the meaning of "local area reliability" and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word "supporting' could be replaced by the phrase "necessary for". In R12 and R13, it doesn't seem possible to measure "monitoring". These also seem like requirements that are ideally suited for the certification process. It appears that the numbering of the requirements within each measure may have gotten out of synch due to a cut and paste insert. In M8, SOLs should be singular. The data retention periods are too long and do not appear to serve the purpose of improving reliability. Specifically, the three (3) year retention period for SOL and IROL violations is two (2) years too long.

Response: Requirement R3 - In the case of Requirement R3, clarity of the text is difficult. First, the SDT offers what the words were meant to state: A Transmission Operator is mandated to contact its Reliability Coordinator about System conditions that either have caused the Transmission Operator to initiate Emergency procedures, or may cause the Transmission Operator to initiate Emergency procedures. Requirement R3 extends that contact to other Transmission Operators that either were identified in the Operational Planning Analysis (OPA) as being affected or the Transmission Operator knows is being affected. The wording is crafted to eliminate the possibility that an auditor would find the Transmission Operator non-compliant when another Transmission Operator not previously identified in any study or any procedure was affected. The words state that if you 'know or expect' impacts on someone than you must contact them to prepare them for the conditions, but if you don't know or expect an entity to be affected, then the requirement does not apply.

Discussion of alternatives: The known or expected is a modifier to "other Transmission Operators." The idea was that the Operating Plan would define the expected; the "known' was to address the fact that a condition could arise that was not expected, but the Transmission Operator now 'knows' (from some other means) that another Transmission Operator (not known from the OPA) was affected. This phraseology was meant to capture that situation where a Transmission Operator finds out a fact that is not in its study. The requirement does not excuse the Transmission Operator just because the other Transmission Operator was not in the analysis – if you 'know' then you are required to contact them. On the other hand, if another Transmission Operator is impacted but your OPA did not identify that impact and you don't have any knowledge of the impact, then Requirement R3 does not apply.

Given the above discussion, alternative 2 would not add clarity – since the "known or expected" modifies Emergency. No change made.

Measure M5 – The SDT agrees and has revised the measure accordingly.

> **M5**. Each Transmission Operator shall make available upon request, evidence that ~~operations~~ it ~~coordinated~~ informed other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas ~~with those Transmission Operators~~ in accordance with Requirement R5 unless conditions did not permit such ~~coordination~~ communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

Requirement R8 - Requirement R8 is a pre-event reporting requirement. This requirement is strictly focused on what to do with the SOLs that are pre-assigned.

Organization	Yes or No	Question 1 Comment
The requirement says if a Transmission Operator wants to address an SOL on the same level as an IROL, then it must inform the Reliability Coordinator of which SOLs are to be raised to that level. Thus, exceedances of SOLs that arise and were not identified in the Operational Planning Analysis will not be covered in Requirement R8. No change made. Requirement R11 – The SDT agrees and has added "within 30 minutes" **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 within 30 minutes. Requirement R14 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT corrected typos including Measure 8. **M8**. Each Transmission Operator shall make available evidence that it has informed it~~'~~s Reliability Coordinator of each SOL~~s~~ which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. For SERC comments, see SERC response.		
FirstEnergy	No	We agree with many of the changes the drafting team made to this standard. However, we have the following comments and suggestions: a. With respect to R7 and R11 in relationship to IROLs, R11 is inherent in R7. If an entity is not permitted to operate outside an IROL limit for longer than its Tv, then it needs to implement whatever actions are required to comply with Tv including directing "others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv." R9 and R11 have the same issue with respect to SOL's. M3 is silent on evidence related to the Operational Planning Analysis. Did the drafting team intend for this data to be available for inspection as a means of proving or disproving the affect on a Neighboring Transmission Operator and thereby the need to contact them? If it is the intent of the drafting team to use the Operational Planning Analysis as evidence, then it should be specifically stated in M3. If it is the intent of the drafting team for an entity to be able to prove "conditions did not permit such coordination" then that evidence should be specified in the measures. b. R11 - We believe that requiring the TOP to mitigate IROLs is outside their scope per the functional model. The RC holds the authority over the tools needed to mitigate an IROL and is the appropriate entity responsible for this requirement. Also, it seems as though this requirement is duplicative of IRO-009-1 R4 which states "When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to

Organization	Yes or No	Question 1 Comment
		mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. (Violation Risk Factor: High) (Time Horizon: Real-time Operations)". c. R13 - We suggest the team remove the phrase "within any Transmission Operator Area" from the requirement. We believe this phrase is not necessary and adds confusion. d. R14 - The original SAR charged with addressing Order 693 directive 1660 required the standards to identify the minimum monitoring and analysis capabilities. The new requirement R14 does not fully address these minimum capabilities and will leave the requirement ambiguous from a compliance and enforcement standpoint. We suggest the team fully address the directive and clarify the requirement. e. Measures M10 through M14 make reference to the wrong requirements.
Response: a. The industry has agreed that violations of IROLs must never occur – hence Requirement R7. Requirement R7 is meant as a flat-out prohibition on violating IROLs – the concept being that IROL violations will/may take down the BES. The industry also seems supportive of extending the IROL violation to some (some would even like to extend the prohibition to all) SOLs which the Transmission Operator decides are important at the local level, hence Requirement R9. Requirement R11 is an action requirement that mandates not just avoiding a violation (Requirements R7 & R9) but to reduce any and all exceedances. The SDT interpreted the industry as wanting to prohibit the Transmission Operator not just to stay within the MW and time margins, but also wanted the Transmission Operators to act when any magnitude limit is exceeded no matter how short a time. Requirement R11 mandates that once the magnitude is exceeded, the Transmission Operator must be taking action. Requirements R7 and R9 force the Transmission Operators to be concerned with any and all System conditions that "can" lead to going over the magnitude and duration limit. While not mandating a multiple Contingency standard, these two requirements force Transmission Operators to be sensitive to (i.e., not ignore) conditions that may result in common mode failures that would not occur during normal conditions. No change made. Measure M3 – The requirement is to 'inform' and the SDT believes that the measure correctly states what evidence is needed to prove that an entity 'informed'. No change made. b. The SDT believes that there are situations where the Transmission Operator must take actions or direct others to act over and above those situations where the Reliability Coordinator does same. No change made. c. This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. d. This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. e. The SDT has corrected the typos.		
Dominion	No	Agree with changes to most requirements and measures, but with exceptions as noted below: R2 - Is covered in R1. Do not agree with entity being subject to non-compliance for same shortcoming under 2 requirements. We suggest R2 be removed or that R1 and R2 be revised so that the requirement to inform the TOP not be included in both. R13 - Is the sentence meant imply that a TOP should monitor or have access to information/facilities in

Organization	Yes or No	Question 1 Comment
		another TOP Area that could impact its TOP Area? If so, we believe the current draft language should be revised to improve clarity of intent. We suggest revising to read "Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within external Transmission Operator Area(s) as necessary to perform such analysis" M1/M2 - revise measures so that entity is not subject to non-compliance for failure to notify TOP twice, pursuant to changes in R1/R2. M8 - change SOLs to SOL. M13 - revise pursuant to R13.
Response: Requirements R1 & R2 (and Measures M1 & M2) - Requirement R1 is written to address a priori prohibitions. These would be communicated at the time the actions were first being communicated. Requirement R2 is written to address conditions that arise after the entity agreed to do the action but found out later that conditions preclude such actions. No change made. Requirement R13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. M8 – The SDT made the indicated revision. **M8**. Each Transmission Operator shall make available evidence that it has informed it~~'~~s Reliability Coordinator of each SOL~~s~~ which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.		
Terry Harbour	No	The proposed TOP-001-2 standard is a significant improvement, but there are still important items that need to be addressed including: Comments cannot be developed for this requirement until a final draft of the definition of Reliability Directive is presented as it will have a significant impact on TOP-001-2 and R1. When Reliability directive is defined, the definition of a Reliability Directive is too broad and should be limited to "Abnormal conditions that require operational actions to avoid instability, uncontrolled separation and cascading as defined in Section 215 of the Federal Power Act." TOP-001-2-R9: SOL's should not be part of the TOP-001-2 standard as there are not identified timeframes in the NERC standards today. However, if SOL's must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded such as 30 minutes after exceeding the specified SOL limit. An example definition might be non-thermal SOL's are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability. Many times scheduled transmission outages coupled with weather (drought, wind front, heat wave, etc) and strong market moves can drive unexpected SOL exceedances where units and markets cannot move within

Organization	Yes or No	Question 1 Comment
		30 minutes to redispatch sufficient generation. Coupling SOLs with time frames and penalties will drive unforeseen market impacts. TOP-001-2-R10: It isn't clear when the RC should be informed, before, during, or after actions have been taken to correct an overload. Depending upon the urgency of the situation, it might not be important to notify the RC, therefore the requirement should be changed to the TOP should record actions taken for future review. For TOP-001-2-R6 replace "coordinate" with "notify the RC and negatively impacted adjacent interconnected NERC registered entities of " For TOP-001-2-R3, the words "and anticipated" needs to be dropped as an unmeasurable requirement. In TOP-001-2-R2 and R4, "expected to be affected" would include known. We asked the SDT to please strike known. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for TOP-001-2-R5 and R8 need to be clear that these are event driven requirements and evidence is only required if an "event" has occurred. In R6, the word "telemetering" should be capitalized as it is a defined term in the NERC Glossary. The terms "control equipment" and "associated communications channels" are not defined in the glossary at all. Recommend modifying the wording to ensure consistency between standards. R14 uses the term "monitoring and analysis capabilities". This term is not defined in the NERC Glossary. R13 implies that a TO's Operational Planning Analyses should be monitoring facilities external to its own operating area when they have no control or responsibility for said facilities. It is not a TO's responsibility to monitor regional system conditions; therefore this requirement should be removed. FERC Order 693, paragraphs 1660 and 1661 do not specifically mention any of the verbiage in requirements R12, R13, & R14; therefore the preceding statement should be considered.
Response: "Reliability Directive" is not meant to equate to urgency of a situation; rather it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the		

Organization	Yes or No	Question 1 Comment

phraseology would raise the text to the same level as an act to relieve the condition itself. No change made.

Requirement R9 - The 30 minute limit is generally recognized as a time related to the risk of a second event occurring, thus 30 minutes is the maximum time. That does not preclude an operator from choosing a shorter duration (lesser restriction – e.g., higher MW) limit and using a shorter duration. No change made.

Requirement R10 - The requirement does define an explicit time. It is the time after an act was taken ("…inform … of its actions…") and after the limit was exceeded ("…to return…when an IROL …has been exceeded…" The communication therefore is not mandated prior to the action being taken. The fact that the communication is about all of its actions precludes communication "during" the action; thus leaving the communications to the post-action time period. The SDT did not see a need to be prescriptive about the reporting time. The proper phrase would be "as soon as time permits," but that phrase does not provide the clarity that compliance enforcer's desire. No change made.

Requirement R6 – The SDT agrees and has revised the wording accordingly.

> **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

Requirement R3 - From a compliance auditor's perspective, the auditor is constrained to depend on the Transmission Operator on whether or not an Emergency is "anticipated". The rationale for the language was to put the Transmission Operator on alert that even the expectation of an Emergency is enough to trigger communications.

Requirement R2 & R4 - Without the phrase "expected to be affected," the requirement would only apply in the case of actual Emergencies (which may be too late to make use of all available options). A real Emergency that is known to impact Transmission Operator X may not necessarily have been shown by the OPA to affect Transmission Operator X. This requirement is written in a way that it does not excuse a Transmission Operator that runs an OPA that has no problems, from its obligation to contact others that it knows are de facto affected. No change made.

Requirement R7 - The issue of percentages was discussed and was evaluated not to be strong enough for this situation. One violation is unacceptable. More than 4 violations of a requirement that addresses BES so directly cannot be mitigated by percentages. No matter how big or how small a Transmission Operator is, non-compliance with this requirement cannot be justified. No change made.

Requirements R5 & 8 – The SDT believes that the wording is correct as stated. No change made.

Requirement R6 – The SDT has changed the wording for clarity.

Requirement R14 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

Requirement R13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

Requirements R12 & R13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

Organization	Yes or No	Question 1 Comment
MRO's NERC Standards Review Subcommittee	No	The proposed TOP-001-2 standard is a significant improvement, but there are still important items that need to be addressed including: Comments cannot be developed for this requirement until a final draft of the definition of Reliability Directive is presented as it will have a significant impact on TOP-001-2 and R1. When Reliability directive is defined, the definition of a Reliability Directive is too broad and should be limited to “Abnormal conditions that require operational actions to avoid instability, uncontrolled separation and cascading as defined in Section 215 of the Federal Power Act.” TOP-001-2-R9: SOL’s should not be part of the TOP-001-2 standard as there are not identified timeframes in the NERC standards today. However, if SOL’s must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded such as 30 minutes after exceeding the specified SOL limit. An example definition might be non-thermal SOL’s are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability. TOP-001-2-R10: It isn’t clear when the RC should be informed, before, during, or after actions have been taken to correct an overload. Depending upon the urgency of the situation, it might not be important to notify the RC, therefore the requirement should be changed to the TOP should record actions taken for future review. For TOP-001-2-R6 replace “coordinate” with “notify the RC and negatively impacted adjacent interconnected NERC registered entities of” For TOP-001-2-R3, the words “and anticipated” needs to be dropped as an unmeasurable requirement. In TOP-001-2-R2 and R4, “expected to be affected” would include known. We asked the SDT to please strike known. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for TOP-001-2-R5 and R8 need to be clear that these are event driven requirements and evidence is only required if an “event” has occurred. In R6, the word “telemetering” should be capitalized as it is a defined term in the NERC Glossary. The terms “control equipment” and “associated communications channels” are not defined in the glossary at all. Recommend modifying the wording to ensure consistency between standards. R14 uses the term “monitoring and analysis capabilities”. This term is not defined in the NERC Glossary. R13 implies that a TO’s Operational Planning Analyses should be monitoring facilities external to its own operating area when they have no control or responsibility for said facilities. It is not a TO’s responsibility to

Organization	Yes or No	Question 1 Comment
		monitor regional system conditions; therefore this requirement should be removed. FERC Order 693, paragraphs 1660 and 1661 do not specifically mention any of the verbiage in requirements R12, R13, & R14; therefore the preceding statement should be considered.

Response: "Reliability Directive" is not meant to equate to urgency of a situation; rather it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made.

Requirement R9 - The 30 minute limit is generally recognized as a time related to the risk of a second event occurring, thus 30 minutes is the maximum time. That does not preclude an operator from choosing a shorter duration (lesser restriction – e.g., higher MW) limit and using a shorter duration. No change made.

Requirement R10 - The requirement does define an explicit time. It is the time after an act was taken ("…inform … of its actions…") and after the limit was exceeded ("…to return…when an IROL …has been exceeded…" The communication therefore is not mandated prior to the action being taken. The fact that the communication is about all of its actions precludes communication "during" the action; thus leaving the communications to the post-action time period. The SDT did not see a need to be prescriptive about the reporting time. The proper phrase would be "as soon as time permits," but that phrase does not provide the clarity that compliance enforcer's desire. No change made.

Requirement R6 – The SDT agrees and has revised the wording accordingly.

> **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

Requirement R3 - From a compliance auditor's perspective, the auditor is constrained to depend on the Transmission Operator on whether or not an Emergency is "anticipated". The rationale for the language was to put the Transmission Operator on alert that even the expectation of an Emergency is enough to trigger communications.

Requirement R2 & R4 - Without the phrase "expected to be affected," the requirement would only apply in the case of actual Emergencies (which may be too late to make use of all available options). A real Emergency that is known to impact Transmission Operator X may not necessarily have been shown by the OPA to affect Transmission Operator X. This requirement is written in a way that it does not excuse a Transmission Operator that runs an OPA that has no problems, from its obligation to contact others that it knows are de facto affected. No change made.

Requirement R7 VSLs - The issue of percentages was discussed and was evaluated not to be strong enough for this situation. One violation is unacceptable. More than 4 violations of a requirement that addresses BES so directly cannot be mitigated by percentages. No matter how big or how small a Transmission Operator is, non-compliance with this requirement cannot be justified. No change made.

Requirements R5 & 8 – The SDT believes that the wording is correct as stated. No change made.

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Requirement R6 – The SDT has changed the wording for clarity. Requirement R14 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirement R13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirements R12 & R13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
PJM	No	There are several issues with Requirement 6: o The requirement assigns responsibility to 3 entities for one task. NERC standards are designed to clearly assign responsibility to provide a clear measurement and allocation of non-compliance. R 6 as worded requires “coordination” between and among each entity. • Coordination is not defined. Does coordination mean “informing” another party? Does it mean “directing a new solution”? Does it mean “asking permission” of a third party? Who is non-compliant when two (or more) parties do not agree with a proposed solution? How many alternatives proposals must be considered? Suggest the requirement be rewritten as a series of independent requirements with sub-bullets to identify specific tasks. Example: Each TOP shall inform all affected reliability entities of planned outages of active real-time communications channels: o Interpersonal channels • Data exchange channels for any BES elements or elements involved in identified IROL computations • Asset direct-control devices (reactive control equipment,...) Each TOP shall inform all affected parties of alternative means to be used for the duration of the proposed outage. Each BA shall inform all affected reliability entities of planned outages of active real-time communications channels: o Interpersonal channels o Data exchange channels for any BES elements or elements involved in identified IROL computations o Asset direct-control devices (regulation control signals; resource dispatch equipment,...)Each GOP shall inform all affected reliability entities of planned outages of active real-time communications channels: o Interpersonal channels o Data exchange channels for any BES elements or elements involved in identified IROL computations o Asset direct-control devices Each reliability entity inform by the TOP in Rx.x, (or by the BA in Ry.y or by the

Organization	Yes or No	Question 1 Comment
		GOP in Rz.z) shall acknowledge the receipt of the information provided in Rx.x (or in Ry.y or Rz.z) to the respective TOP (BA or GOP). Requirement #13Delete the phrase "...within ANY Transmission Operator Area". The phrase has the potential to add confusion rather than clarity to the requirement.
Response: Requirement R6 – The SDT has modified the requirement to address your concern. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. Requirement R13 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
IRC Standards Review Committee	No	Requirement #1 Comments cannot be developed for this requirement until we are able to see a final draft of the definition of Reliability Directive. It will have a significant impact on this requirement. Requirement #9 A 30-minute time limit has been identified in Requirement 9, but that may be an inappropriate time based upon the variability that exists with actual system operating limits. In the case of thermal limits, some may be 15 minutes others may be 4 hours for different facilities. The same facility may have a 4 hour loading limit, and a 2 hour limit at a higher magnitude, as well as, perhaps, a 30 minute limit at a higher magnitude yet. If the limits were allowed to only be set at 30 minutes, how are longer limits incorporated? Of course it is imprudent to operate a facility at the magnitude corresponding to a four hour limit for greater than four hours. But how is that limit identified and communicated if the System Operating Limit must be mitigated within 30 minutes? Any such operating parameter will be recognized as an SOL, then requiring a 30 minute limit if Requirement 9 is left as is. Requirement 8 mandates that limits be set to support local area reliability. Operating a facility for five hours at its four hour limit is contrary to that requirement. Transmission Operators need SOLs to be described and communicated in terms of both magnitude and associated time, but that time need not be limited to 30 minutes. The duration and magnitude of the SOL should be set by the Transmission Owners or Operators based upon respecting the facility and equipment ratings as required by the FAC standards. Requirement 9 would better serve reliability to require SOLs (which are identified in Requirement 8) to be described in specific terms of both magnitude and associated time. If needed, a fallback position could be maintained that establishes 30 minutes as the default time limit if no other limit is specifically defined in the SOL.

Organization	Yes or No	Question 1 Comment
		Requirement #13 It is not clear what TOP area needs to be monitored. Language needs to be added to clearly state that a TOP should have access to information on other TOP areas that could impact his local area.
Response: **“**Reliability Directive” is not meant to equate to urgency of a situation; rather, it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator’s request or is debating the request can be “made to” to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made. Requirements R8 & 9 - The issue posed by the IRC seems to be more academic than real. Requirement R8 does not mandate that any SOL be defined. Requirement R8 only requires that a Transmission Operator tell its Reliability Coordinator of those SOLs that the Transmission Operator has decided it wants the Reliability Coordinator to treat in the same fashion as the Reliability Coordinator would treat IROLs. IRC is using its definition for SOL not the Requirement R8 definition. Requirement R8 defines SOL as a limit that the Transmission Operator itself has designated for monitoring and control by the Reliability Coordinator. Every operating limit does not automatically come under that requirement. However, if a Transmission Operator wants every operating limit to be addressed by the Reliability Coordinator in the same way that the Reliability Coordinator addresses IROLs, then that is allowed under this requirement. If the Transmission Operator wants none of its operating limits handled like an IROL, that too is allowed under the requirement. The Transmission Operator requirements protect the BES under the IROL requirements; these non-IROL limits are optional. NERC has used a 30-minute time frame for several Contingency-related standards based on a review that showed the risk of a second Contingency is greatly increased after 30 minutes. While a 4-hour rating may be used, if a single Contingency were to occur, there would be no problem, but a second Contingency would be a problem. While the requirement does not mandate reserves for multiple Contingencies, the requirement does impose a time frame of 30 minutes. There is no one SOL for a Facility. Each Facility has an infinite number of magnitude vs. duration curves. No change made. Requirement R13 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	No	R1 - ERCOT ISO does not agree with the addition of the word ‘identified’ because it implies each Reliability Directive needs to be preceded with an additional statement like “the following is a Reliability Directive”. In a true emergency, clear concise communication and an understanding of what action is required to mitigate the situation is necessary. The addition of another sentence before each required action delays communication. ERCOT ISO thinks a Reliability Directive should not have to be declared as such, prior to issuance. Compliance should not be measured by whether the System Operator remembered to state “this is a Reliability Directive”, but should be measured by whether the Reliability Directive was properly issued and three-part communication was utilized. NOTE: Requirements 1 and 2 are dependent upon the approval of the term Reliability Directive, which is being proposed by Project 2006-06 Reliability Coordination.

Organization	Yes or No	Question 1 Comment
		R2 - Add Operations Planning to the Time Horizon because R1 includes Operations Planning in the Time Horizon. R1 and R2 occur in the same Time Horizons, since R1 requires an entity to comply to a Reliability Directive issued by a TOP and R2 requires an entity who cannot comply to notify the issuing TOP.NOTE: Requirements 1 and 2 are dependent upon the approval of the term Reliability Directive, which is being proposed by Project 2006-06 Reliability Coordination. R9 VSL - The TOP, when notifying the RC, should identify the appropriate Tv. The associated VSL should be high and not severe and should only be severe when multiple instances occur.
Response: Reliability Directive is not meant to equate to urgency of a situation; rather, it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. Communications between registered entities occur almost continuously. Within those communications are instructions from Reliability Coordinators and Transmission Operators. Those instructions are expected to be followed at all times. However, there are times when people question instructions. At those times, the recipient of an instruction that is identified as a Reliability Directive needs a clear understanding that it is a Reliability Directive. The requirement is consistent with the ERCOT position that added words should not be mandated; the difference is that the ERCOT proposal would mandate the repeating of actions, whereas the requirement does not. No change made.. Requirement R2 – The SDT has added the time horizon as requested. **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]* Requirement R9 – If a VSL is binary, and the SDT believes that this VSL should be binary, it must be Severe. No change made.		
Joylyn Faust	No	R2 is ambiguous, must a BA inform it's TO of an inability to perform a directive after the directive has been issued or at anytime its systems are down and it has temporarily lost its ability to perform some function. R12-14 appear to provide the TO with omnipotent information rights which may include the ability to create monitoring requirements of other entities and control over maintenance schedules of other entities telemetry and associated facilities. Furthermore reciprocal data rights are not provided.
Response: Requirement 2 - R2 is an after-the-request requirement. If, after being given a Reliability Directive, the entity finds out that its equipment cannot perform as expected, Requirement R2 mandates the entity tell the Reliability Coordinator so that the Reliability Coordinator may make other arrangements. If the		

Organization	Yes or No	Question 1 Comment
system were down, then other NERC requirements mandate that such conditions be communicated. This requirement is just designed for states when the entity expects to be able to do something but finds out that it cannot. No change made. Requirements 12-13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Jonathan Appelbaum	No	"Operational Planning Analysis" is not a defined term in the NERC Glossary and a proposed definition is not included in the Draft Standard. TOP-001 and TOP-002 have capitalized the term indicating a definition. TOP-002 information box says "by definition Operational Planning Analysis includes Contingency Analysis." TOP-001 R12 and R13 were added in this posting to address Order 693 paragraph 1660 and 1661 direction to include the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. The drafting team utilizes the phrase "shall monitor, or shall have access to information about, conditions and Facilities..." By offering an alternative to "monitor" the drafting team is implying there is a difference between "monitor" and "having access to information". UI suggests retaining "monitor" and removing "access to information about" because the TOP needs the minimum capability of monitoring the Facilities in its area to perform its reliability functions.
Response: Operational Planning Analysis is in the Glossary. No change made. Requirements 12 and 13 have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Jon Kapitz	No	R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. Xcel Energy has concerns about the use of the term "affected". This can be widely interpreted by the entity and compliance enforcement authority. We suggest that language limit the entity's obligation to Adjacent entities and the Reliability Coordinator. The RC should be held responsible for making this assessment from a regional perspective and make notifications to other entities as it is required to or deems necessary. R13. Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. Xcel Energy has concerns as to whether this requirement indicates that a TOP must have monitoring capability for other TOP areas. This requirement should encompass only a TOP's own area. R14. Each Transmission Operator shall provide approval rights for planned maintenance of its monitoring and analysis capabilities to its System Operators. Xcel Energy believes this requirement should be worded so that it covers only monitoring capabilities for its own area, and items that it is in control of. (e.g. not feeds from other entities that input into a TOPs own monitoring capability)

Organization	Yes or No	Question 1 Comment
		M11 through M14 list incorrect associated requirements. This appears to be a mapping issue.
Response: Requirement 3 - The SDT respects the sensitivity of regarding the term "affected." The SDT perspective was to avoid the possibility that any and every 'affect' in Real-time would come under this requirement, and inserted the phrase "… expects to be affected…" This would mean that if the Transmission Operator "expected" to affect another entity, then Requirement R3 would require the Transmission Operator to communicate that expectation. However, if the Transmission Operator did not expect to impact a third-party, then there would be no obligation. As written, the requirement provides a common sense approach. To be found non-compliant, an auditor would have to show evidence that the Transmission Operator knew that there would be an impact and knowingly did not inform the impacted entity. This would require an auditor to peruse data and make a case. It is possible to show non-compliance, but it will be the auditor's responsibility to prove that fact, as opposed to the Transmission Operator being subject to proving that. While the Reliability Coordinator is responsible for ensuring that every entity knows its role, this requirement recognizes that the Transmission Operator can have a role in analyses and information that may not be analyzed in the detail that the Transmission Operator can provide. No change made. Requirement 13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirement R14 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT has corrected the typos in the measures.		
Howard Rulf	No	R7: What does it mean to be "outside" an IROL? Vague. R8: Since any SOL is to "ensure operation within acceptable reliability criteria" this requirement requires that the TOP inform the RC of all SOLs. How can the Time Horizon be Real-Time Operations? Operational Planning Analysis is done at least day ahead? R9: What does it mean to be "outside" an SOL? Vague. R10: How do I correlate "within limits" to "inside/outside"?
Response: Requirements 7, 9, & 10 - The term "outside" was used to recognize that there are both upper and lower limits. No change made. Requirement 8 – Requirement R8 is an a priori requirement. All it is meant to say is "if a Transmission Operator wants its Reliability Coordinator to observe a given non-IROL limit in the same way as the Reliability Directive observes IROLs, then the Transmission Operator must tell that Reliability Coordinator which limits are in that category. This must be done ahead of time. It can be done in the OPA or in the Long-term planning horizon or any other advanced time – it cannot be done in Real-time (where Real-time is defined as 'this instant') or after-the-fact. No change made.		
RoLynda Shumpert	No	In R3 the language should be "...be affected by actual..." and not "...be affected of actual..." Measures M10-M14 are off by 1 in pointing back to their respective requirements (i.e. M10 is pointing back to

Organization	Yes or No	Question 1 Comment
		R9, etc). It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: Requirement 3 – The SDT has revised Requirement R3 to address your comment and those of others. **R3.** Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. The SDT has corrected the typos.		
Greg Rowland	No	What does the drafting team mean by "its inability" in R2 to perform a Reliability Directive? There clearly needs to be a distinct difference between the reasons in R1 and "inability" in R2. Duke wants to eliminate the possibility of double jeopardy for an entity to be assessed a possible violation for non-compliance to one action with it stated similarly in two requirements. R3 typo - change the word "of" to "by". R8 - the phrase "supporting its local area reliability" is unclear. Replace it with the phrase "having an Adverse Reliability Impact". This adds clarity and also recognizes that local area problems that don't rise to the level of Adverse Reliability Impact should not be treated as SOLs required to be reported to the RC under this standard. R9 - insert the phrase "as having an Adverse Reliability Impact" after the phrase "Requirement R8", making R9 consistent with R8. R13 - strike the phrase "shall monitor, or". The TOP doesn't need to directly monitor facilities in other TOP areas. M1 - strike the word "either" and replace the phrase "or, (b) informed the Transmission Operator that" with the word "unless". This makes M1 consistent with the R1 revision above. M3 typo - replace the word "of" with the word "by". M5 typo - the word "operations" appears twice. Need to strike the first one. M8 - replace the phrase "supporting its local area reliability" with the phrase "having an Adverse Reliability Impact", consistent with the R8 revision above. M13 - strike the phrase "can monitor, or" consistent with the R13 revision above. R1 VSL - replace the phrase "and the respective entity did not inform the Transmission Operator that such

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		action would" with the phrase "and compliance with the Reliability Directive would not", consistent with the R1 revision above. VSLs for R3, R5, R6 and R8 - The mixing of numbers with percentages and the phrase "whichever is less" in these VSLs is confusing. For example, if under R5 there are four affected entities, and the TOP does not coordinate operations with one of the four, then that is one entity, or 25% of the total. What does "whichever is less" mean? Is that a Lower or Severe violation? Conversely, if there is only one affected entity and the TOP does not coordinate operations with that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation? R8 VSLs - In each VSL, replace the phrase "supporting its local area reliability" with the phrase "having an Adverse Reliability Impact, consistent with the R8 revision above. R13 VSL - Strike the phrase "monitor, or", consistent with the R13 revision above.

Response: Requirements 1 & 2 - Requirement R1 is written to address a priori prohibitions. These would be communicated at the time the actions were first being communicated. Requirement R2 is written to address conditions that arise after the entity agreed to do the action, but found out later that conditions preclude such actions. No change made.

Requirement 3 – The SDT revised the requirement to address your comment.

> **R3.** Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

Requirement 8 - Local area reliability is not a defined term but rather (as stated in the requirement) it is "based on its (the Transmission Operator's own) assessment." The industry has debated this issue for a long time. This standard is written to ensure BES reliability by defining IROLs and by supporting individual Transmission Operators parochial definitions. The loss of a capital city in a state may have no impact at all on the BES, but publicly that city is critical (think Washington, DC). Requirement R8 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). Given that the requirement is for local concerns that could mean that the limit is not necessary for local reliability but rather "supports" local reliability. No change made.

Requirement 9 - An SOL that has adverse reliability impacts is, by definition, an IROL. Requirement R8 says that if it isn't an IROL and you want the limit to be controlled in the same way as an IROL, then tell the Reliability Coordinator which limits you want. [Note what all this means –when running its planning and or operating analysis, the Reliability Coordinator does not find the said limit as causing any BES problems – thus the Reliability Coordinator is not concerned with the said limit. The Transmission Operator however, wants, or is required by some other authority, to treat the said limit as if that limit had BES implications. Such information must be conveyed by the Transmission Operator to the Reliability Coordinator.] Thus, inserting the proposed text will not accomplish the intent of the requirement. No change made.

Requirement 13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis

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Capabilities. The SDT reviewed the typos and made the changes where deemed appropriate. The mixing of numbers and percentages is standard for VSLs. It is designed to allow for size differences in applicable functional entities. 'Whichever is less' means simply that you use the option that is less numerically. No change made.		
Michael Lombardi	No	Both Requirements R12 and R13 are considered vague and open to interpretation. For example, what type of information is to be monitored and what is meant by conditions? Language needs to be added to clearly state what a TOP needs to accomplish pursuant with these requirements. Various Measures appear to have incorrect Requirement references. For example, the text of Measure M14 refers to Requirement R13. Please verify / correct the Requirement references for all Measures. The term "Operational Planning Analysis", is capitalized to identify it as a defined term yet the NERC Glossary of Terms (updated 4/20/2010) indicates that the term has not been FERC approved. NU is concerned that the terms Operational Planning and Operational Planning Analysis are not FERC approved and may not be consistently applied throughout the industry. Suggest these terms be reviewed as part of this standard to ensure industry consensus on these terms and subsequently seek FERC approval, as required.
Response: Requirements 12-13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT has corrected the typos. Operational Planning Analysis is contained in the NERC Glossary. Once it is approved by the BOT, the SDT is required to use the term. No change made.		
Richard Kafka	No	R6 requires coordination which leads to questions regarding who is non-compliant. It would be more proper to require reporting and approval requirements. RCs already are required to coordinate with each other. R9 sets a 30 minute limit on all identified SOLs (as opposed to allowing different times). This would require all facilities to have the same time limits for ratings. That should be addressed in FAC-008.
Response: The SDT has revised Requirement R6 to address your concerns. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. NERC has used a 30-minute time frame for several Contingency-related standards based on a review that showed the risk of a second Contingency is greatly increased after 30 minutes. While a 4-hour rating may be being used, if a single Contingency were to occur, there would be no problem, but a second		

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Contingency would be a problem. While the requirement does not mandate reserves for multiple Contingencies, the requirement does impose a time frame of 30 minutes. There is no one SOL for a Facility. Each Facility has an infinite number of magnitudes vs. duration curves. No change made.		
Saurabh Saksena	No	R13 states that - Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. What does “Facilities” in R13 refer to? Is it any facilities that are included in the analysis or those that have the potential to cause violations? Suggest replacing “...Facilities identified in its Operational Planning Analysis” by text in R8 - “...identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis.” TOP-001 R13 also says "...within any Transmission Operator Area...” Does the drafting team mean within that particular TOP's area? It would be clearer if it said "...within its area...” If they really do mean another TOP's area, that is unrealistic. It could imply that we need to have info for TOP in Florida. TOP-001 R8 & TOP-002 R2 - When referencing SOLs both say something like "SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability...” National Grid suggests deleting “...which, while not IROLs...”
Response: <u>Requirement 13</u> – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. <u>Requirement 8 -</u> The wording “while not IROLs” was inserted to make clear that not all limits have adverse reliability impacts, but that some limits that do not have reliability impacts can still be held to a higher standard of operations - as long as those limits are identified. An SOL that has adverse reliability impacts is by definition an IROL. Requirement R8 says that if it isn’t an IROL and you want the limit to be controlled in the same way as an IROL, then tell the Reliability Coordinator which limits you want. [Note what all this means –when running its planning and/or operating analysis, the Reliability Coordinator does not find the said limit as causing any BES problems – thus the Reliability Coordinator is not concerned with the said limit. The Transmission Operator however, wants, or is required by some other authority, to treat the said limit as if that limit had BES implications. Such information must be conveyed by the Transmission Operator to the Reliability Coordinator.] Thus, inserting the proposed text will not accomplish the intent of the requirement. No change made.		
Catherine Koch	No	R1 - The addition of the term “identified” does not completely answer the question of who needs to identify the communication as a Reliability Directive. Simply adding the term means that it might be interpreted to mean that that the entity receiving a communication from a Transmission Operator might need to identify the communication as a Reliability Directive from its content and context. The following formulation is more clear: “Each Balancing Authority ... shall comply with each Reliability Directive that its Transmission Operator issues and identifies as a Reliability Directive ...” Given the importance of these requirements, clarity must not be sacrificed for brevity. R8 - The use of the phrase “have been identified” is unnecessary in this requirement. The Transmission

Organization	Yes or No	Question 1 Comment
		Operator has an independent obligation to identify these SOLs under the FAC standards. In addition, the phrase "its local area reliability" is ambiguous. If the intent of this term is to address a certain set of SOLs that have more than a purely local effect, then the phrase should be modified to something like "regional reliability" or "that may affect its neighboring Transmission Operator Areas". The requirement should read "Each Transmission Operator shall inform its Reliability Coordinator of all SOLs that, while not IROLs, support regional reliability based on its assessment of its Operational Planning Analysis" or "Each Transmission Operator shall inform its Reliability Coordinator of all SOLs that, while not IROLs, that may affect its neighboring Transmission Operator Areas based on its assessment of its Operational Planning Analysis." M1 - To be consistent with the recommended revisions to R1, the measurement should be revised to read "Each Balancing Authority ... (a) complied with each Reliability Directive that its Transmission Operator issued and identified as a Reliability Directive, ...". Additionally we suggest that the measures provide guidance of how to prove a Reliability Directive was not issued in order to be complete in demonstrating compliance with the requirement. This same suggestion rings through all the measures.M2 - This measurement duplicates a portion of M1.
Response: Requirement 1 & Measure M1– The SDT does not agree that the suggested change adds any clarity. No change made. Requirement 8 - Technically you are correct that the phrase is not needed. However, in this transitional period when a term is being parsed in a special way, the added words are seen (in this case) to be helpful. The words were crafted to mean "local issues." An outage affecting the White House would not be an impact on the BES but "locally" it would be unacceptable; thus a limit that impacted the White House would be identified by the DC Transmission Operator to the Reliability Coordinator as a special case SOL that must be respected in the same way an IROL is handled. Thus Requirement R8 does mean local and does not refer to impact on others. Note inter-area impacts would be more likely identified by the Reliability Coordinator than the Transmission Operator since the Reliability Coordinator has more intelligence on surrounding areas. No change made.		
Jason Shaver	No	Requirements #1 & 2 ATC supports Requirements 1 and 2 if the definition of Reliability Directive, as provided in TOP-001-2, is not modified. Any change to the proposed definition of Reliability Directive will require us to reevaluate our position. Requirement #3 Issue 1: ATC is concerned with the wording of Requirement 3 because it blends real time Emergencies situations with issues or concerns that are identified in Operational Planning Analysis for next day, week, month or year. Definitions: "Emergency" and "Operational Planning Analysis": Emergency: "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the BES" Operational Planning Analysis: "An analysis of the expected system condition for the next day's

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		operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generation outages, equipment limitations, etc.).” If an Emergency by definition requires automatic or immediate manual action then there would be few if ever a situation in which a next day study would require either automatic or immediate manual action. What reliability objective is the SDT attempting to achieve when combining these two distinct situations into one requirement? Because of this observation ATC believes that the language about anticipated Emergency and Operational Planning Analysis should be deleted. If the SDT does not believe that these deletions are necessary then we request that the SDT provide additional clarify for the phrase “anticipated Emergency”. Supporting TOP Standard:TOP-002-3 addresses the need for a TOP to perform an Operational Planning Analysis and when appropriate to develop a plan based on those results. That plan must be communication to Registered Entities that have to perform an action. *(See ATC's Comments to TOP-002)* Because TOP addresses next day studies we believe that there is no need for this requirement to also cover Operational Planning Analysis. Clarifying questions: Does the Operational Planning Analysis have to be performed by the TOP itself? (Situation: Currently MISO does a next day study for its footprint. Could that qualify as an Operations Planning Analysis being performed, or does each TOP have to perform its own next day study.) Requirement 3: “... based on its assessment of its Operational Planning Analysis. ”Issue 2: When is notification required to take place? ATC believes that the primary responsibility of the system operator is to address the actual (real-time) Emergency and then when appropriate follow up with the RC and other TOP's. The only exception is when the TOP has to issue a Reliability Directive which would be issued in response to the situation. Requirement 5: ATC believes that the second sentence should be deleted because all it is attempting to do is provide examples. The first sentence provides enough clarity, so that the second sentence is not needed and may result in more confusion. Requirement 6: Issue 1: Who qualifies as an “affected entity”? If the entity is not registered with NERC how can NERC verify that coordination took place? Does this mean that a TOP, BA and GOP would have to contact customers if the planned outage could affect them? How affected does an entity have to be in order to trigger coordination? Measure 6 states that the TOP, BA and GOP must coordinated “among impacted reliability entities” but there does not exist a definition of “reliability entities”. This standard should clearly set the expectations as to who does the TOP, BA and GOP have to coordinate with and not

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		make the requirement so broad to allow questions about who was involved in the coordination. Issue 2: It is not clear as to when a planned outage of telemetering and control equipment and associated communication channels has to be coordinated. Requirement 7: ATC believes that the term “outside” is not clear and that the SDT should either define the term or use a more appropriate term. Suggested Modification: Modification to R7: “Each TOP shall not “exceed” an identified IROL...” Requirement 8: ATC raised a question on Requirement 3 asking if each TOP has to perform its own Operations Planning Analysis. Based on the answer to that question this requirement may need to be deleted. If an Operations Planning Analysis can be performed by the RC then there would be no need for the TOP to contact the RC about the results of their own study. We believe that Requirement 2 of TOP-002-3 covers Operational Planning Analysis so there is no need to have a duplicate requirement.ATC is unclear as to what this requirement is attempting to achieve. Is this requirement simply saying that the TOP has to share their system operating limits with the RC? If that is the case we believe that the requirement should be rewritten to provide that specific clarity. Suggested Modification: The TOP shall inform the RC of all BES System Operating Limits (SOLs) that support local area reliability. Requirement 9: Issue 1: The proposed requirement is too restrictive because it prevents the TOP from applying loss of life assumption on its equipment. We believe that entities should be able to determine when exceeding equipment limits is appropriate based on the situation and equipment. Suggested Modification:- The TOP may exceed (real-time) a SOL for a continuous duration of 30 minutes. In addition we believe that the TOP should be allowed to use the IROL Tv concept to allow an SOL to be exceeded for a continuous duration of greater than 30 minutes if they notify the RC of the longer SOL Tv. Requirement 10: It is not clear as to when the notifications must take place. Would notifying the RC following the exceedance of the IROL or SOL be okay, or, must the TOP contact the RC prior to taking action in order to be compliant with this requirement? Requirement 12:

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		ATC believes that this requirement is unnecessary because it is only saying that a TOP has to know what is going on with its system. In order to be compliant with the other requirements in this standard a TOP understands that by default they must monitor as appropriate its system. The challenge this requirement introduces is that it is so broad that demonstration of compliance is overly burdensome. In addition this requirement is unclear as to what and how often the TOP has to monitor, or have access to information to demonstrate compliance. Questions: • If a TOP has a 4 second scan rate for EMS data and if a single data scan is missed or an error occurs at a single point does this mean that the TOP is non-compliant? • If an entity uses information on a RC website about planned outages and for some time that system is unavailable for any length of time will the TOP be non-compliant because they don't have access to information? • What does the requirement mean by the phrase "conditions and Facilities"? • Does this mean that the ROP has to monitor breaker statues, switch statues, transformer temperatures, wind conditions and ambient temperatures? • Proposed suggestion: ATC believes that this requirement should be deleted. Requirement 13: This requirement will reduce reliability because it will force TOP's to use the smallest base case model to perform its Operational Planning Analysis. We believe our statement is accurate because it requires the TOP to have an EMS model that matches the Operational Planning Analysis model. So if an entity performs off-line studies (non EMS studies) that use the Eastern interconnection then they must also monitor or have accession to information for the Eastern Interconnection. Since access to all if information is highly unlike or unnecessary to gather the TOP will have to use the model contained in their EMS to perform Operational Planning Analysis. Although this may not necessary be a bad thing a TOP will loss the benefits of using the larger model to perform Operational Planning Analysis. If the RC performs the Operational Planning Analysis then by this requirement does the TOP have to monitor everything in the RC's Operational Planning Analysis model? Suggested Modification: ATC believes that this requirement should be deleted.

Response: "Reliability Directive" is not meant to equate to urgency of a situation; rather, it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the

Organization	Yes or No	Question 1 Comment
System Operator. The exact words needed to affect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made. Requirement 3 – Issue 1: First, Requirement R3 only refers to the assessment of the OPA. The SDT offers what the words were meant to convey: A Transmission Operator is mandated to contact its Reliability Coordinator about System conditions shown in the OPA that will cause the Transmission Operator to initiate Emergency procedures, or may cause the Transmission Operator to initiate Emergency procedures. Requirement R3 extends that contact to other Transmission Operators that either were identified in the OPA as being affected or the Transmission Operator knows are being affected. The wording is crafted to eliminate the possibility that an auditor would find the TOP non-compliant when another Transmission Operator is not previously identified in any study or any procedure. The words state that if you 'know or expect' impacts on someone, then you must contact them to prepare them for the conditions; but if you don't know or expect an entity to be affected, then the requirement does not apply. Requirement 3 links all of the prior conditions to the OPA. That is intended to provide an explicit measure and to mitigate the worry that Requirement R3 applies to any and all impacts. To delete the language about "anticipation" would change the requirement from a requirement that uses an OPA as a reference point, to a requirement that has no reference point. As written, the Transmission Operator can document what it "anticipated." As ATC proposes, the Transmission Operator must satisfy an auditor's subjective view of "anticipate". No change made. There is no requirement that the Transmission Operator do the OPA. The only requirement is that the OPA be performed if the other requirements (e.g., impact on others) can be carried out. No change made. There is no requirement on timing. The requirement is written to accommodate ATC's concern that real-time actions are more important than procedural mandates. The ATC question seems to be requesting the requirement be converted into an administrative procedure. There is no one correct time period to inform others. The requirement is written to recognize that conditions not rules must dictate the response. The Transmission Operator would only be hurting itself if it did not tell others that the Transmission Operator needed them to relieve a problem. If the impact took down the System, the Transmission Operator as well as its neighbor would be hurt. No change made. Requirement 5 – The SDT worded this requirement to comply with a FERC Order 693 directive. No change made. Requirement 6 – Issue 1: The SDT has revised the wording of the requirement to address your comment as well as those of others. Issue 2: planned = any time ahead of fact. No change made. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. Requirement 7 - The term "outside" was used to recognize that there are both upper and lower limits. No change made. Requirement 8 - The ATC suggestion that the Reliability Coordinator, not the Transmission Operator, do the OPA would impose a regional control of Facilities. Today, Transmission Operator s plan, commit, and operate their Facilities for their regulatory defined areas. Those "local" plans are fed to the Reliability Coordinator, which has the right to adjust the local plans based on wide-area considerations. The current Industry approach incorporates local reliability margins. That process is much different than the one ATC is proposing. The ATC proposal would in effect impose the Reliability Coordinator's reliability perspective on all local areas (now the Reliability Coordinator imposes its control over the performance – actual and expected-- of the areas not over the commitment or local margins). The ATC model of total Reliability Coordinator control is not prohibited by the current requirement, but it does not mandate the ATC model. Requirement R3 says nothing about SOLs; Requirement R3 merely requires the Transmission Operator to share advanced warning information (warnings		

Organization	Yes or No	Question 1 Comment
obtained via the OPA) with its Reliability Coordinator. That does not mean the Transmission Operator need not share information that it obtains normally for from other sources. It just says if you predict an emergency based on the OPA, then give others a "heads-up." No change made. Requirement 9 - The debate around SOLs centers on some people's conception that there is one and only one "limit." There is another perspective that forms the basis of this standard and that is both IROLS and SOLs can be a series of values: A lower value that can be used forever, and higher values that can be sustained for shorter time durations. Requirement R9 is only "too prescriptive" if the former concept (of one limit) is used. Requirement R9 is not prescriptive at all. If the Transmission Operator has only one limit, then that value must be used. But if the Transmission Operator has a series of curves, Requirement R9 does not preclude switching magnitude limits from one value to another (and of course switching T_v s from one value to another). However, if the Transmission Operator places a magnitude and a duration on the limit-set, then that limit set must be respected. If ATC uses a 500 MW continuous rating than as long as the flow is 500 MW or less there is not issue. But if the flow exceeds 500 MW, then ATC would either change the limit-set or correct the flow. It must be understood that the Transmission Operator itself has decided (via Requirement R8) that it wants the Reliability Coordinator to handle this particular limit in the same way that the Reliability Coordinator handles IROLs. Why would a Transmission Operator designate a Facility in Requirement R8 and then want to ignore it? No change made. Requirement 10 - There is no requirement on timing. The requirement is written to accommodate ATC's concern that Real-time actions are more important than procedural mandates. The ATC question seems to be requesting the requirement be converted into an administrative procedure. There is no one correct time period to inform others. The requirement is written to recognize that conditions not rules must dictate the response. The Transmission Operator would only be hurting itself if it did not tell others that the Transmission Operator needed them to relieve a problem. If the impact took down the System the Transmission Operator as well as its neighbor would be hurt. No change made. Requirement 12 & 13 – These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Michael Gammon	No	Requirements R3 & R5 requires TOP's to notify all other "affected" or have an "adverse reliability impact" TOP's of an emergency condition. The terms "affected" and "adverse reliability impact" is a debatable condition and subject to interpretation. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Recommend the requirement be modified to alert other TOP's whenever a TOP in an emergency condition becomes aware of operating conditions that would result in exceeding an SOL or IROL operating limits under N-1 contingency conditions for other TOP facilities. Modifications for these two requirements will result in subsequent changes to the Measures and VSL's for requirements R3 & R5.
Response: Requirement 3 - Requirement R3 is written as an advanced warning and is centered on the OPA results. Requirement R3 is about forecasted (OPA) "expectations". If the Operational plans 'forecast' that the next day's operation will (or is likely) to result in Emergency operations, Requirement R3 says to tell the Reliability Coordinator and the other Transmission Operator s who are explicitly shown to be involved (e.g., they may be needed to carry out a part of the Emergency Operating procedures – such entities are "known" to be involved). On the other hand, there may be "indications" that other Transmission Operators may or may not be involved. Since such an evaluation is indeed subjective (i.e., based on the Transmission Operator's perspective), the requirement is written to bias the Transmission Operator to informing the "expected to be affected" Transmission Operators. You are correct that this part of the requirement is problematic for auditors who are seeking to punish a Transmission Operator. But the standard is not written for punishment purposes, it is written to drive proper actions. The		

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<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">proper action is “when in doubt tell the other party.” An auditor cannot (and should not attempt to) measure such marginal/subjective conditions. The SDT believes the words are consistent with NERC’s position to write standards that support reliability. No change made.

<u>Requirement 5 - </u>Requirement R5 is written as an implementation (of Emergency Operating Procedures) requirement. Requirement R5 is about real-time expectations. If a Transmission Operator knows that its Emergency operations will adversely impact another Transmission Operator in Real-time, then that Transmission Operator is required to inform the latter entity. As with Requirement R3, there is a reliability objective and there is a measureable event. There is also subjectivity in categorizing the “intent.” If a Transmission Operator states in its logs or other documents that act X will impact Transmission Operator “A,” then that Transmission Operator “knows” and is therefore obligated to follow up; likewise, if a Transmission Operator in its logs or other documentation states that act Y is likely to impact Transmission Operator ‘A,” then that Transmission Operator is obligated to follow up. A Transmission Operator can supply documents to prove that it followed up. Proving a negative is not expected by this requirement. No change made.</td></tr>
<tr><td>Leland McMillan</td><td>Yes</td><td>NorthWestern Energy appreciates this chance to comment. NorthWestern supports the definition of "Reliability Directive" as indicated in the Definitions section.

R13 could be clarified to specify the exact types of information about conditions and facilities identified that the entity must have access to.

Also, NorthWestern seeks clarification as to why the requirement mandates that the TOP shall have this information "within any Transmission Operator Area"? Perhaps the intent of the requirement is geared towards TOPs obtaining operating information pertaining to their own TOP area, regardless of which TOP area it is actually physically located in?

NorthWestern requests that the drafting team consider flexibility in the implementation timelines of this standard. Compliance with this standard might require Transmission Operators to acquire/arrange for Operational Analysis and planning simulation tools not currently required by any FERC approved standards.</td></tr>
<tr><td colspan="3">Response: <u>Requirement 13 </u>- This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

Regarding the data -- the requirement as written is linked to the respective Transmission Operator’s Operational Planning Analysis process. If the respective Transmission Operator requires a piece of data for that analysis, then Requirement R12 mandates that the Transmission Operator get information about the item in question. To mandate every item would either be too much for some Transmission Operators and too little for others. There is no one analysis format that was found to fit all Transmission Operators. Addressing the FERC Order with a minimum list would violate FERC’s other requirement that NERC standards not reflect minimum common denominators.

This requirement is designed to require Transmission Operators to follow up on any items that are highlighted in the Transmission Operator’s plans. If the operational plan points to a situation (e.g., a Facility in another area) then the Transmission Operator must make accommodations to obtain information about that facility. That does not mean that the Transmission Operator must have an RTU feed from the Facility, but it does mean that the Transmission Operator must make arrangements to get the information/communications somehow (e.g., having the neighbor report a line flow periodically, or report when the flow exceeds some predetermined value…). The context of the requirement is that if a Transmission Operator needs information to do its reliability studies then that</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
Transmission Operator should get the information even if that information is from a non-adjacent entity. Take for example a 3000 MW DC line between two Interconnections. That line could carry a 3000 MW interchange schedule. The loss of that line could affect a third party Transmission Operator with an impact greater than the Transmission Operator's largest Contingency. In such a case, it would be necessary for all parties to agree to how much interchange will be allowed. Moreover the non-adjacent Transmission Operator may want to be informed of what the loading of the DC line is so as to maintain the security of its own Transmission Operator area. This example would also involve Reliability Coordinators, but the point is that if there is a need than the Transmission Operator is obligated to get sufficient information (not metering just information – like a phone call) to ensure that the System is reliable. No change made. The requirements are written from the perspective of the Transmission Operator and "its" tools; not from the perspective of an auditor and what the audit believes is the right tool. The requirements do not impose common tools or data or lists (see comments to others who want such lists ostensibly to protect themselves). The requirements are written to recognize that a Transmission Operator may be as small as one line or as large as half an Interconnection. The tools and data and procedures must of necessity be different and these requirements respect that diversity. No change made.		
Northeast Power Coordinating Council	Yes	In R9, to clarify the requirement to operate below a System Operating Limit (SOL), "outside" should be replaced with the wording "at or above".
Response: The term "outside" was used to recognize that there are both upper and lower limits. To insert "at or above" could be construed by some people as not including "at or above." No change made.		
Darryl Curtis	Yes	
Dan Rochester	Yes	We applaud the SDT of its positive response to our previous comments regarding the lack of monitoring of and requirement to operate within SOLs. Although the revisions do not go all the way to ensuring operating within all SOLs, and mitigating exceedances as they occur, the revised standard goes a long way in meeting that general intent. We agree with all the changes to the Time Horizons, Measures, data retention and compliance elements (VRFs and VSLs).
Kasia Mihalchuk	Yes	
PacifiCorp	Yes	
Response: Thank you for your support		
Western Electricity Coordinating Council		Under R1 of the standard the word "identified" is used to describe a specific type of Reliability Directive issued by the Transmission Operator. Who performs the work or makes the identification of an "identified" reliability directive? Why under R2 is the classification not carried on to describe the RC directive such as "of its inability to

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<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>perform an IDENTIFIED Reliability Directive"?</td></tr>
<tr><td colspan="3">Response: As written, the Transmission Operator would "identify" an action as a Reliability Directive. No change made.

The SDT has revised Requirement R2 as suggested:

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform a<u>n identified</u> Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: <u>Operations Planning, </u>Same Day Operations, Real-time Operations]</td></tr>
<tr><td>Randi Woodward</td><td></td><td>Minnesota Power does not have any comments at this time.</td></tr>
</table>

2. TOP-002-3: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: The SDT edited the text box for the rationale for Requirement R1 and adjusted the wording for Requirement R3 and M3 based on industry comments to provide additional clarity and to make the intent of the SDT clear.

R3. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

M3. Each Transmission Operator shall have evidence that it notified all ~~reliability~~ registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

Organization	Yes or No	Question 2 Comment
Public Service Enterprise Group Companies	No	The Rational to R1 should add language to clarify that in some circumstances the failure or unavailability of the usual tools may result in the inability to perform a complete and comprehensive analysis. Therefore the words "to the extent practicable" should be added (see below) in the last sentence after the word "able."Rationale for Requirement R1:By definition, Operational Planning Analysis includes Contingency analysis. By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have analysis tools or procedures to perform the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, if tools are used, the Transmission Operator must be able to the extent practicable to complete the analysis even if those tools are not available.
Response: What is required is to have an effective Operational Planning Analysis. How that is provided is up to the entity. Introducing phrases and qualifiers such as “to the extent practicable” would result in something that cannot be measured. No change made.		
Bonneville Power Administration	No	R2 Although an entity does not plan to operate above the SOL, a contingency may cause an short SOL excursion until planned mitigation action is completed within the Tv (allowable violation time limit). Non-electrical people could get confused by this distinction. Suggest clarifying SOL as intended to be path loading limits and/or local area transmission service support limits, (the BES is a big system with lots of ratings, it can also mean voltage limits in addition to line and path limits).
Response: T_v is defined only for Interconnection Reliability Operating Limits (IROL). While the SDT agrees with your statements that short excursions may occur within an applicable time which respects Equipment Ratings, that time may vary significantly from one SOL to another. The suggestion to clarify SOL as intended to be path loading limits or local area Transmission service support limits is problematic as those terms are not universal in use nor are they defined. Requirement		

Organization	Yes or No	Question 2 Comment
R2 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). No change made.		
SERC OC Standards Review Group	No	In R2 and M2, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”.
Response: IROLs are the subset of SOLs that “…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.” The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Reliability Coordinator or Transmission Operator has determined to be important to supporting reliability in a local area. No change made.		
Southern Company Transmission	No	Southern's comments: The current NERC Glossary definition of Operations Planning Analysis does not explicitly include contingency analysis. Unless the SDT is modifying the definition of Operations Planning Analysis to include contingency analysis, we recommend that R1 be re-expanded to include the expectation of performing contingency analysis. Regarding R2 and M2, a TOp should not plan to operate beyond any SOL limit - regular or one that “is supporting local reliability.” Otherwise, why should it be classified as an SOL? SERC's comments: Southern participated in developing these comments and support them. In R2 and M2, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”.
Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue: R2 and M2**:** IROLs are the subset of SOLs that “…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.” The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Reliability Coordinator or Transmission Operator has determined to be important to supporting reliability in a local area. No change made. SERC’s comments: Knowing SOLs is important for situational awareness (know where you are and where you expect to operate) and for determining whether Adverse Reliability Impacts may result from exceeding them. If such an adverse impact is predicted, there is potential that the SOL is indeed an IROL. If it does		

Organization	Yes or No	Question 2 Comment
not meet the qualifiers as an IROL, but it is important to a local area, the Transmission Operator (or a Reliability Coordinator, for that matter) may designate such an SOL for the Reliability Coordinator to include in the limits that must be honored and mitigated as soon as possible, but no longer than 30 minutes. No change made.		
MRO's NERC Standards Review Subcommittee	No	The rationale box needs to be clarified. If the drafting team meant for entities to have a primary set of tools / procedures and backup set as well, please clarify that. "By definition, Operation Planning Analysis includes Contingency analysis" is not accurate. The definition in the Glossary of Terms mentions nothing of contingency analysis. It mentions known transmission and generation facility outages, but that has nothing to do with contingency analysis, which includes a study of unknown events to occur on current system conditions. Therefore, the requirement should read "Each Transmission Operator shall have an Operational Planning Analysis that incorporates potential single contingency events." Is "plan" in requirement R2 a noun or verb? It appears to read as if it is a verb, which implies no documented action would be necessary. If intended, it should read "Each Transmission Operator shall develop a plan...." This flows much better with what the intent of R2 is trying to say.
Terry Harbour	No	The rationale box needs to be clarified. If the drafting team meant for entities to have a primary set of tools / procedures and backup set as well, please clarify that. "By definition, Operation Planning Analysis includes Contingency analysis" is not accurate. The definition in the Glossary of Terms mentions nothing of contingency analysis. It mentions known transmission and generation facility outages, but that has nothing to do with contingency analysis, which includes a study of unknown events to occur on current system conditions. Therefore, the requirement should read "Each Transmission Operator shall have an Operational Planning Analysis that incorporates potential single contingency events." Is "plan" in requirement R2 a noun or verb? It appears to read as if it is a verb, which implies no documented action would be necessary. If intended, it should read "Each Transmission Operator shall develop a plan...."
Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. 'Plan' in Requirement R2 is a verb. It is the process of putting together the operations plan for whatever timeframe is applicable. Part of that process includes the performance of an Operational Planning Analysis. No change made.		
Joylyn Faust	No	The proposed standard which indicates the TO shall "notify" reliability entities as to "their role" appears to be bolstering the authority of the TO. During real time events the TO should have authority to issue directives, however on a planned basis TOs should coordinate, not dictate the role of the entities. On a planned basis,

Organization	Yes or No	Question 2 Comment
		input from the involved entities will result in a more reliable system.
Response: The requirement, following the coordination required to develop an operating plan, is to notify the entities that have roles in the operating plan, and what those roles are. For example, those entities may have actions to perform, or they may have Facilities that will be impacted by actions taken by others. Reliability Standard TOP-002-3 pertains to Operations Planning. The execution of the operations plans developed within the requirements of TOP-002-3 is covered in other standards. The SDT agrees that input from the involved entities will result in a more reliable System, but once that input has been received and a plan has been put into place, those entities with roles in the plan must be notified as to what are those roles. No change made.		
Jon Kapitz	No	R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. Xcel Energy believes this requirement is confusing as written. It appears to want to include all SOLs. If so, why not just state as such? It could be simply stated as "...IROLS and SOLS..." R3. Each Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). Xcel Energy believes this should be limited to just entities within the TOP's own area.
Response: IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Transmission Operator has determined to be important to supporting reliability in a local area. Requirement R2 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). No change made. Knowing SOLs is important for situational awareness (know where you are and where you expect to operate) and for determining whether Adverse Reliability Impacts may result from exceeding them. If such an adverse impact is predicted, there is potential that the SOL is indeed an IROL. If it does not meet the qualifiers as an IROL, but it is important to a local area, the Transmission Operator may designate such an SOL for the Reliability Coordinator to include in the limits that must be honored and mitigated as soon as possible, but no longer than 30 minutes. No change made.		
Howard Rulf	No	Rationale for Requirement R1: Operational Planning Analysis does not include Contingency analysis "by definition". "Contingency analysis" does not appear in the definition of Operational Planning Analysis. R2: Since any SOL is to "ensure operation within acceptable reliability criteria" this requirement requires that the TOP include all SOLs in their "plan". R3: When is this notification to take place? Since this analysis starts taking place as much as 12 months in

Organization	Yes or No	Question 2 Comment
		advance, as the plan changes over time there could be multiple conflicting notifications.
Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. R2 - IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Reliability Coordinator or Transmission Operator has determined to be important to supporting reliability in a local area. Knowing SOLs is important for situational awareness (know where you are and where you expect to operate) and for determining whether Adverse Reliability Impacts may result from exceeding them. If such an adverse impact is predicted, there is potential that the SOL is indeed an IROL. If it does not meet the qualifiers as an IROL, but it is important to a local area, the Transmission Operator (or a Reliability Coordinator, for that matter) may designate such an SOL for the Reliability Coordinator to include in the limits that must be honored and mitigated as soon as possible, but no longer than 30 minutes. No change made. R3 – After the Transmission Operator runs an Operational Planning Analysis and determines another entity as having a role in their plan and before the affected entity has to take action, they should notify the affected entity. No change made.		
RoLynda Shumpert	No	In "Consideration of Comments on First Draft of Revised TOP Standards Real-Time Operations - Project 2007-03," p77, #6 response, March 26, 2009, it was stated that "reliability entities" is not a defined term. In addition, in "Consideration of Comments on Second Draft of Standards for Real-Time Operations (Project 2007-03)," pp 64-65, August 25, 2009, a response is given to Xcel Energy's comment that the phrase reliability entities needs definition that "reliability entities are the entities certified by NERC as such." SCE&G believes that it is unclear what is meant by "certified by NERC as such" and would appreciate that these entities be spelled out as it relates to these Standards. It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: Reliability entities: The SDT has changed the wording to 'registered entities.' **R3**. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). The SDT has checked all the references and made corrections as needed.		
Greg Rowland	No	R2, M2 and R2 VSL - Replace the phrase "supporting its local area reliability" with the phrase "having an Adverse Reliability Impact". This adds clarity regarding which SOLs must be addressed in the TOP's plan. R3 VSL - The mixing of numbers with percentages and the phrase "whichever is less" in these VSLs is

Organization	Yes or No	Question 2 Comment
		confusing. For example, if there are four affected entities, and the TOP does not notify one of the four, then that is one entity, or 25% of the total. What does “whichever is less” mean? Is that a Lower or Severe violation? Conversely, if there is only one affected entity and the TOP does not notify that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation?
Response: R2, M2, and R2 VSL: Replacing the phrase “supporting its local area reliability” with the phase “having an Adverse Reliability Impact” would be inappropriate because the definition of Adverse Reliability Impact clearly indicates impact to a widespread area of the BES, not just a local area. No change made. R3 VSL: The mixing of numbers and percentages is standard verbiage for VSLs. It is designed to allow for size differences in applicable functional entities. ‘Whichever is less’ means simply that you use the option that is less numerically. No change made.		
Michael Lombardi	No	The rationale box for Requirement R1, indicates that TOP must be able to complete analysis even if the tools that are used are not available. It is not clear how contingency analysis would be performed if study tools are not available. What if day ahead study tools are part of an Energy Management System (EMS) which is a high reliability redundant system with an independent system at a back up facility? Is the rational box verbiage suggesting one would need to postulate the loss of a redundant EMS as well as its back up facility? Please clarify what is to be accomplished pursuant with R1. The term “Operational Planning Analysis”, is capitalized to identify it as a defined term yet the NERC Glossary of Terms (updated 4/20/2010) indicates that the term has not been FERC approved. (See additional write up in Question 1 comment)
Response: What is required is to have an effective Operational Planning Analysis. How that is provided is up to the entity. The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. The following definition is taken from the NERC Glossary of Terms Used in the Reliability Standards: “Operational Planning Analysis: An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).” This definition has been approved by the NERC BOT but not yet approved by FERC. NERC BOT approval gives the definition operational authority. No change made.		
Saurabh Saksena	No	TOP-001 R8 & TOP-002 R2 - When referencing SOLs both say something like "SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability...". National Grid suggests deleting “...which, while not IROLs...”.,

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td colspan="3"> Response: The wording “while not IROLs” was inserted to make clear that not all limits have adverse reliability impacts, but that some limits that do not have reliability impacts can still be held to a higher standard of operations - as long as those limits are identified. An SOL that has adverse reliability impacts is by definition an IROL. Requirement R8 says that if it isn’t an IROL and you want the limit to be controlled in the same way as an IROL then tell the Reliability Coordinator which limits you want. [Note what all this means –when running its planning and/or operating analysis, the Reliability Coordinator does not find the said limit as causing any BES problems – thus the Reliability Coordinator is not concerned with the said limit. The Transmission Operator however, wants, or is required by some other authority, to treat the said limit as if that limit had BES implications. Such information must be conveyed by the Transmission Operator to the Reliability Coordinator.] Thus, inserting the proposed text will not accomplish the intent of the requirement. No change made. </td></tr>
<tr><td>Catherine Koch</td><td>No</td><td> R1/R2 - The side-bar indicates that Contingency analysis is included Operational Planning Analysis by definition. The definition of Operational Planning Analysis, however, does not discuss or even mention Contingency analysis. Recommend a revision to the definition of Operational Planning Analysis to clarify that such an analysis does include Contingency analysis. R2 - See comments regarding identified SOLs under requirement R8 of TOP-001-2 above. </td></tr>
<tr><td colspan="3"> Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. R2: See response to comments regarding identified SOLs under requirement R8 of TOP-001-2. </td></tr>
<tr><td>Jason Shaver</td><td>No</td><td> Rational Box: The SDT states that by definition Operational Planning Analysis includes Contingency Analysis. ATC does not agree with this statement and therefore we requests that the SDT removed this statement. Operation Planning Analysis: “An analysis of the expected system condition for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generation outages, equipment limitations, etc.).”The definition does not specifically call out contingency analysis but is specific that an Operations Planning Analysis is a next day study which can be performed any time from a day ahead to as much as 12 months ahead. Time Horizon: In TOP-001-2 Requirement 2 the SDT calls on Operations Planning Analysis to be performed and identifies it as either a Same-Day Operations, Real-Time Operations Time Horizon requirement. In TOP-002-3 Requirement 1 the SDT is calling for Operations Planning Analysis to be performed and identifies it as a Operations Planning Time Horizon. ATC finds it very confusing that the SDT is using this defined term in multiple Time Horizons and believes that a single time horizon be used for this term. </td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		Requirement 1:If a TOP were to perform an Operations Planning Analysis for TOP-001-2 then what different Operations Planning Analysis would a TOP have to do be in compliance with Requirement 1 of TOP-002-3? Requirement 2: ATC believes that Requirement 2 (TOP-002-3) conflicts with TOP-001-2 Requirement 9. Requirement 9 in TOP-001-2 allows a TOP to exceed an SOL for a continuous duration of 30 minutes but that same allowance is not provided in requirement 2. (Note: see ATC's comment to Question 1 requirement 9.) ATC believes that the same continuous duration time provided in Requirement 9 of TOP-001-2 be allowed in Requirement 2. Requirement 3: ATC believes that additional clarity is needed around the use of the term "role". We believe that this requirement is calling for TOP's to contact other Registered Entities if they have an "action" to perform in the plan. Is ATC's understanding of the term "role" consistent with the SDT's understanding? A TC also believes that the phrase "reliability entities" should be replaced with Registered Entities.

Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue.

Time Horizon: Time Horizon refers to the time period for mitigating a violation to the requirement, not an operating timeframe. TOP-001-2, Requirement R2 does not address Operational Planning Analysis. Requirement R3 does mention Operational Planning Analysis and does apply to the Same Day Operations and Real-Time Operations Time Horizons. TOP-002-3 pertains to Operations Planning, while TOP-001-2 pertains to multiple Time Horizons. No change made.

Requirement 1: If the Operational Planning Analysis performed includes all the relevant expected conditions, it may be appropriate for a next-day analysis, same-day analysis, or Real-time analysis. However, if any actual System conditions differ from the assessed conditions, the entity must decide whether the analysis continues to cover the potential reliability impacts. If not, then the analysis should be updated. No change made.

Requirement 2: TOP-002-3, Requirement R2 pertains to Operations Planning. TOP-001-2, Requirement R9 pertains to Real-time Operations. The assessment of an Operational Planning Analysis in Operations Planning may "predict" that an SOL or IROL will be exceeded, but it does not predict a duration of that exceedence. In Real-time Operations, the entity must be taking mitigation actions whenever an exceedence is identified. If that exceedence cannot be mitigated within 30 minutes, then the exceedence becomes a violation. No change made.

Requirement 3: The requirement, following the coordination required to develop an operating plan, is to notify the entities that have roles in the operating plan, and what those roles are. For example, those entities may have actions to perform, or they may have Facilities that will be impacted by actions taken by others. No change made.

Reliability entities: The SDT has changed the wording to 'registered entities'.

R3. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

Organization	Yes or No	Question 2 Comment
Jonathan Appelbaum	Yes	"Operational Planning Analysis" is not a defined term in the NERC Glossary and a proposed definition is not included in the Draft Standard. TOP-001 and TOP-002 have capitalized the term indicating a definition. TOP-002 information box says "by definition Operational Planning Analysis includes Contingency Analysis."
Response: The following definition is taken from the NERC Glossary of Terms Used in the Reliability Standards: "Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." This definition has been approved by the NERC BOT but not yet approved by FERC. NERC BOT approval gives the definition operational authority. No change made. The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue.		
Dan Rochester	Yes	Again, we applaud the SDT of its positive response to our previous comments regarding the lack of consideration to SOLs in operational planning. Although the revisions do not go all the way to ensuring TOPs plan their operations to respect all SOLs, the revised standard goes a long way in meeting that general intent. We agree with all the changes to the Time Horizons, Measures, data retention and compliance elements (VRFs and VSLs).
IRC Standards Review Committee	Yes	No comment at this time. (The YES box was inadvertently checked, which we are unable to de-select)
Northeast Power Coordinating Council	Yes	
Michael Gammon	Yes	
E.ON U.S.	Yes	
Midwest ISO Standards Collaborators	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
Dominion	Yes	
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	Yes	
Kasia Mihalchuk	Yes	
Leland McMillan	Yes	
Richard Kafka	Yes	
Response: Thank you for your support.		
Randi Woodward		Minnesota Power does not have any comments at this time.

3. TOP-003-1: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: No comments were received that required contextual changes to the requirements. Some semantic changes were made for additional clarity to Requirement R1 and the Measures.

R1. Each Transmission Operator and Balancing Authority shall ~~have~~ create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

R1, Part 1.1, bullet #1 - Long term outages of Bulk Electric System (BES) equipment~~, as specified by the Transmission Operator or Balancing Authority~~

R1, Part 1.1, bullet #2 - Operating parameters for equipment of the BES and at voltage levels lower than the BES~~Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority~~

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

Organization	Yes or No	Question 3 Comment
SERC OC Standards Review	No	We believe that R5 is redundant to R4 if the Transmission Operator is added to R4.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Group</td><td></td><td></td></tr>
<tr><td>Dominion</td><td>No</td><td>It is not clear how the data provision obligations of BAs under requirement R4 are different from their obligations under R5. We therefore suggest that TOP be added to R4 and that R5 be removed.</td></tr>
<tr><td colspan="3">Response: The SDT felt it appropriate to distinguish the individual aspects of the data requirements. Requirement R1 notes that data requirements will be established by the Transmission Operator and Balancing Authority. Requirement R2 covers the Transmission Operator’s responsibility to make the requirements known. Requirement R3 does the same for Balancing Authorities. Requirement R4 requires that other entities respond accordingly to the requests for data. And Requirement R5 requires the Transmission Operators and Balancing Authorities to share that data with other Transmission Operators and Balancing Authorities that need the data. Clarity in the requirements, especially with regard to specific roles and responsibilities of involved entities was the goal. Layered in this manner, it provides a control for data requests to be made through the Balancing Authority or Transmission Operator for the area, rather than having Transmission Operators or Balancing Authorities requesting data from non-Transmission Operators or non-Balancing Authority entities within another area without also assuring the data was known and provided to the host Transmission Operator or Balancing Authority. This may have been done through other approaches but the SDT chose this approach to achieve the desired clarity. No change made.</td></tr>
<tr><td>Southern Company Transmission</td><td>No</td><td>Southern's comments:M4 and M5, there should be allowance for outstanding requests that are still within the deadline as defined in R1.4.

SERC's comments: Southern participated in developing these comments and support them We believe that R5 is redundant to R4 if the Transmission Operator is added to R4.</td></tr>
<tr><td colspan="3">Response: The SDT presumed the meaning was clear that outstanding requests referenced only those which have exceeded the time to respond and agrees that additional clarity is required. Revisions were made to Measures M4 & M5.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled<u> and are outside of the deadline in Requirement R1, Part 1.4</u>.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled<u> and are outside of the deadline in Requirement R1, Part 1.4.</u>

The SDT felt it appropriate to distinguish the individual aspects of the data requirements. Requirement R1 notes that data requirements will be established by the Transmission Operator and Balancing Authority. Requirement R2 covers the Transmission Operator’s responsibility to make the requirements known. Requirement R3 does the same for Balancing Authorities. Requirement R4 requires that other entities respond accordingly to the requests for data. And Requirement R5 requires the Transmission Operators and Balancing Authorities to share that data with other Transmission Operators and Balancing Authorities</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
that need the data. Clarity in the requirements, especially with regard to specific roles and responsibilities of involved entities was the goal. Layered in this manner, it provides a control for data requests to be made through the Balancing Authority or Transmission Operator for the area, rather than having Transmission Operators or Balancing Authorities requesting data from non-Transmission Operators or non-Balancing Authority entities within another area without also assuring the data was known and provided to the host Transmission Operator or Balancing Authority. This may have been done through other approaches but the SDT chose this approach to achieve the desired clarity. No change made.		
MRO's NERC Standards Review Subcommittee	No	Remove "at the discretion of the Transmission Operator or Balancing Authority" in R1-1.1. The TO and BA are the entities creating the specification, which already implies that any needed parameters are at their discretion. Overall clarification seems necessary on this bullet as well (R1-1.1). Why specifically address equipment of voltage levels below BES levels? Does this exclude equipment rated 100 kV and above? Replace "Real-time monitoring" with "Real-time Assessment" as this is an actual term in the NERC Glossary of Terms. This would follow a similar format to the "Operational Planning Analyses".
Terry Harbour	No	Remove "at the discretion of the Transmission Operator or Balancing Authority" in R1-1.1. The TO and BA are the entities creating the specification, which already implies that any needed parameters are at their discretion. Overall clarification seems necessary on this bullet as well (R1-1.1). Why specifically address equipment of voltage levels below BES levels? Does this exclude equipment rated 100 kV and above? Replace "Real-time monitoring" with "Real-time Assessment" as this is an actual term in the NERC Glossary of Terms. This would follow a similar format to the "Operational Planning Analyses".
Response: The SDT was careful to be explicit and specifically clear in the requirements. However, the comment does point out an opportunity for additional clarification. **R1, Part 1.1, bullet #1** - Long term outages of Bulk Electric System (BES) equipment~~, as specified by the Transmission Operator or Balancing Authority~~. **R1, Part 1.1, bullet #2** - Operating parameters for equipment of the BES and at voltage levels lower than the BES~~Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority~~. The SDT believes that the wording is correct as stated. No change made.		
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	No	R1.1 - The phrase 'to be exchanged' seems to be unnecessary. M2 and M3 - These measures allude to evidence of information actually being distributed, yet some companies make information available to entities through website posting or other public forums. Please

Organization	Yes or No	Question 3 Comment
		include showing proof of availability of information to an entity as an option in these measures. M4 - The last sentence should be revised to match the last sentence of M5. Consider rewording both M4 and M5 as follows: "The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled." The R2 and R3 VSLs have percentage approaches, but the R4 and R5 VSLs are binary, even though there are multiple elements to data specifications referred to in R4 and R5. All four of these requirements should have percentage approaches. Similarly, there are requirements for the RC (in IRO-010) to document data specifications. The associated IRO-010 R1 and R2 VSLs also have a percentage based approach. To be consistent, the TOP-003-2 R4 and R5 VSLs need to be changed to the percentage based approach for consistency.

Response: R1.1 – The SDT does not see that the suggested change adds any additional clarity. No change made.

M2 & M3 – The SDT has revised the measures based on your comments.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4 & M5 – Clarifications have been made to measures M4 and M5.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

R2 & R3 VSL – The SDT believes that there is a reliability-based difference to distribution of the specification versus supply of the data and that the VSLs reflect this difference. No change made.

Organization	Yes or No	Question 3 Comment
Style changes.Dan Rochester	No	M5: The last sentence added is in fact a requirement. Measures should not include requirement for “completeness” of the data provision, which is already implicit in R5. The extent to which the data is not fully provided should be assessed and reflected by the VSLs. Suggest to delete this sentence and as desired, expand the VSLs for R5 to make them graded according to the percentage of data not provided.
Response: -Measure M5 was changed due to industry comments. The measure created is a binary one. There are either outstanding (i.e., unfilled or unaddressed) requests for data, or there are not. The SDT can see no additional requirements added to the standard by this measure. No change made to the VSL. **M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.		
Joylyn Faust	No	Poorly worded. According to the proposed standard the TO is supposed to “exchange” data, at its discretion, regarding equipment ratings at voltage levels below the BES. So when our TO demands HVD equipment ratings, what are we to exchange it with? Again, this standard appears to be bolstering the authority of the TO. If the TO can demand information from the DP, then the DP should have access to similar information regarding the TO’s system.
Response:- The standard is enabling the Transmission Operator to meet its reliability obligations. These obligations do not extend to the same degree or scope to the Distribution Provider. Therefore, there is not the same need for data by the Distribution Provider as there is for the Transmission Operator. The standard is appropriately establishing the levels of authority for data gathering as needed for reliability and in keeping with the established functional model. No change made.		
John Fish	No	M4. "The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled." Should be removed The response to the "request for data", or an attestation that no requests have been made, should stand alone as proof of GO/GOP compliance??
Response: -Measure M5 has been changed to address industry comments. **M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.		
Howard Rulf	No	TOP-003-2R1: Nowhere in NERC Standards is a TOP or BA required to perform an Operational Planning Analysis. This requirement applies to data specifications. It does not require Operational Planning Analysis.

Organization	Yes or No	Question 3 Comment
		R1.2: Who mutually agrees to the format? The TOP and BA? A TOP or BA may have scores of different entities with Facilities within their boundaries. Is this requiring data format agreements with scores of other entities? The TOP and BA should be allowed to specify the data format. R4: Please explain what is meant by “satisfy the obligations of the documented specifications for data”. Please rephrase this to something more clearly understandable in the requirement. R5: Consider modifying this requirement so that the data is provided directly where possible. Data received indirectly through other entities is delayed, and there are increased chances of problems in receiving the data.
Response: R1 - This standard addresses data specifications and the obligations to provide and share data, as appropriate, and as needed, to perform reliability analyses for operations planning as required in proposed TOP-002-3. No change made. R1.2 - The requirement does not mandate “format agreements” with anyone. The mutual agreement is between the provider and the requester of the data. In this regard it is reasonable to expect that a standard format will emerge, but it is not required. The SDT believes this approach is the best way to avoid placing unreasonable format requirements into the standard. No change made. R4 – “Satisfy the obligations” means to supply the requested data according to the requirements. The SDT does not see any problem with the present wording and absent any suggested wording does not see any reason for changing the current wording. R5 – The requirement does not tell an entity how to handle data, just what data needs to be delivered. No change made.		
RoLynda Shumpert	No	It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: The SDT will review and correct as needed prior to the next posting.		
Greg Rowland	No	R2 and R3 VSLs - The mixing of numbers with percentages and the phrase “whichever is less” in these VSLs is confusing. For example, if there are four entities, and the TOP or BA does not distribute its data specification to one of the four, then that is one entity, or 25% of the total. What does “whichever is less” mean? Is that a Lower or Severe violation? Conversely, if there is only one entity and the TOP does not notify that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation?
Response: R2 & R3 VSL – The SDT believes that there is a reliability-based difference to distribution of the specification versus supply of the data and that the VSLs reflect this difference. No change made.		
Randi Woodward	No	Minnesota Power has the following comments for the individual requirements of the proposed Standard TOP-003-2.Requirement 1 o The time horizon doesn’t appear to match the requirement.

Organization	Yes or No	Question 3 Comment
		o The tasks required to accomplish the items listed in sub-requirements R1.1 - R1.4 also fall under the responsibility of a Reliability Coordinator, in addition to the Transmission Operator and Balancing Authority functions that are already listed in this Requirement. o The term “mutually agreeable format” is confusing and needs more definition to eliminate any confusion regarding who is required to agree on the format in sub-requirement 1.2. Requirement 4 o The way this Requirement is currently worded could leave the door open for disparate specifications. As currently written, Registered Entities are obligated to abide by all specifications regardless of feasibility or ability to implement. Minnesota Power requests more clarification regarding what is meant by “satisfy the obligations of the documented specifications for data.” Requirement 5 o The way this Requirement is currently written it could open the door for a liberal interpretation of the Requirement and could result in excessive data requests in the name of “Operational Planning Analysis and Real-time monitoring.” Minnesota Power suggests revising the Requirement to state that the requesting Transmission Operator and/or Balancing Authority must demonstrate a reliability need in its request for data.
Response: Time Horizon refers to the time period for mitigating a violation to the requirement, not an operating timeframe. The SDT has reviewed the current Time Horizons and feels it is appropriate. No change made. Reliability Coordinator responsibilities are covered in other standards. There may be similar data requirements for Reliability Coordinators, but that doesn’t negate the need for such data by the Transmission Operators and Balancing Authorities. Additional requirements for other entities do not conflict with this requirement, which stands on its own. No change made. Mutually agreeable is self-explanatory and is between the requester and the provider of the data. No change made. “…satisfy the obligations of the documented specifications for data…” is clear in that the data, specified by the Transmission Operator or Balancing Authority in the requesting documentation must be provided as requested to satisfy the obligation. The SDT thinks this requirement is clear. No change made. Demonstrating a reliability need for data is unnecessary. There is no expectation that a Transmission Operator or Balancing Authority would request data that is unneeded. There is a burden placed onto the Transmission Operator and Balancing Authority to manage the data requested, and an expectation that data will be used and useful. It is not reasonable to expect that unneeded data will be requested as there is no incentive to make such a request, and some incentive not to do so. No change made.		
Catherine Koch	No	R1 - As indicated in the first full row on page 5 of the document “Resolution of Issues Assigned to Real-time Operations SDT (Project 2007-03)”, FERC staff disagrees with the data specification approach. How does the SDT propose to deal with this disagreement? Given this disagreement and FERC’s current concerns with NERC’s standard approval process, what purpose does continuation of the current approach accomplish? R1.2 - The phrase “mutually agreeable format” may lead to disputes between the TOP and other entities

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>subject to the TOP’s data specification. In the event that the entities cannot agree, the TOP’s reasonable requirements should trump.

R1.4 - There should be language added that requires agreement to proposed deadline by the entity receiving the specification as there could be a need for programming work and it could be foreseen that the deadline indicated can not be reasonably met.</td></tr>
<tr><td colspan="3">Response: R1 – NERC staff believes, and the SDT concurs, that the data specification approach outlined here and in the proposed IRO standards is a more effective approach to data handling and is working with FERC staff to bring this issue to a satisfactory conclusion. No change made.

R1.2 and R1.4 - If there is a disagreement that cannot be handled by the entities involved, the SDT believes that existing conflict resolution agreements would be used to resolve the dispute. No change made.</td></tr>
<tr><td>Jason Shaver</td><td>No</td><td>Requirement 1.1: ATC believes that requirement 1.1 is unnecessary and opens up other issues and therefore should be deleted from this standard. Long-term outage information while important is not directly related to EMS data. In addition, information about facilities that operate below 100 kV is beyond FPA 215 and is beyond NERC’s jurisdiction.</td></tr>
<tr><td colspan="3">Response: It is correct that the requirement for data does indeed extend beyond EMS data. This is the intent of the requirement. This data is needed to enable appropriate operations planning for conditions (which real-time EMS scans would not represent) throughout the Operations Planning Horizon, as is the intent of the requirement. Facilities below 100 KV may have material impact to the BES and, as such, are within the scope of the requirement and must, as determined necessary by the host Balancing Authority or Transmission Operator, be included. No change made.</td></tr>
<tr><td>Michael Gammon</td><td>No</td><td>Requirement R4 may be troublesome for small Registered Entities to meet the data requirements dictated by larger Registered Entities. The is no recognition of the limitations of data exchange capability with an entity. Recommend requirement R4 be modified to include "within the data exchange capabilities of the recipient of the data specification". Modifications here would result in changes to the Measure and VSL for requirement R4.</td></tr>
<tr><td colspan="3">Response: It is not anticipated that a data request would be made for data that is not reasonably available. Nonetheless, the concept of a standard in this regard is to assure that data needed for reliable operations is made available, as appropriate. This standard incorporates the ability for Transmission Operators and Balancing Authorities to adjust data requirements to meet the needs of regional areas, while maintaining a standard. The SDT believed this approach superior to one which mandated a one-size-fits-all data requirement, which would result in either insufficient data because the standard was too weak (accommodating various levels of data gathering capabilities), or too stringent in some cases (as potentially described in this comment), thereby creating unreasonable data requests in some cases. The SDT used this approach to enable addressing the concern raised here as would not be possible in the one-size-fits-all approach. No change made.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	We commend the drafting team for attempting to manage the evidence in a way that does not require the TOP to get evidence to prove an absence of an issue, however, the following statement needs clarification to remove the double negative verbiage, "The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled." This statement might be improved by stating "The evidence shall be the Transmission Operators and Balancing Authorities requests have been met." This will allow the entity to show the requests received from other entities and the evidence that they filled those requests.
Response: The SDT has revised the measures based on your comments and those of others**.** **M4.** Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4. **M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.		
IRC Standards Review Committee	Yes	No comment at this time. (The YES box was inadvertently checked, which we are unable to de-select)
Northeast Power Coordinating Council	Yes	
Public Service Enterprise Group Companies	Yes	
E.ON U.S.	Yes	
Midwest ISO Standards Collaborators	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 3 Comment
PacifiCorp	Yes	
Jonathan Appelbaum	Yes	
Kasia Mihalchuk	Yes	
Jon Kapitz	Yes	
Michael Lombardi	Yes	
Leland McMillan	Yes	
Richard Kafka	Yes	
Saurabh Saksena	Yes	
Response: Thank you for your support.		

4. The implementation plan compares the already approved requirements in the "TOP" standards with those that are proposed in TOP-001-2, TOP-002-2, and TOP-003-2. When comparing the already approved standards with those that are proposed, how would you assess the impact to reliability of the proposed standards are approved and the already approved standards are retired in accordance with the implementation plan?

Summary Consideration: Some commenters said that reliability would be improved, while the vast majority of the commenters said that the changes would either not affect or would improve reliability.

Two commenters indicated reliability would suffer. Of those two, one had a technical comment that was able to be addressed directly and which should be resolved. The other had no specific comments to support the contention that reliability would be reduced as a result of these changes.

The SDT made the following changes due to comments:

TOP-001-2, R6 - Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

Organization	Yes or No	Question 4 Comment
Joylyn Faust	There will be an adverse impact to reliability	See previous responses.
Response: Please see previous comment responses.		
Jason Shaver	There will be an adverse impact to reliability	Operational Planning Analysis: ATC is concerned with the use of the term Operational Planning Analysis in both TOP-001 and TOP-002. Once something is called an Operational Planning Analysis all associated requirements apply. Although the SDT is attempting to draw a distiction between contengency analysis which typically runs off and EMS and more traditiional PSS/E or power flow studies those requirements that talk about monitor or access to information apply equally. Example: If an entity chooses to uses a Eastern Interconnection base model to satisfy TOP-002 Requirement 1 that entity would have to also have to be in compliance with TOP-001 Requirement 13. Requirement 13 states that the TOP has to monitor or have access to information about condition and Facilities. By default a TOP would have to have access to information about every facility in the Eastern Interconnection model in order to be in compliance with calling

Organization	Yes or No	Question 4 Comment
		the study a Operational Planning Analysis and By using the same term to represent different study time frames causes a number of compliance issues with this standard. We suggest that the team either determines a single meaning for the term Operational Planning Analysis or clarifies the compliance obligations around the different time frames for Operational Planning Analysis.
Response: This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
MRO's NERC Standards Review Subcommittee	There will be no change to reliability	There seems to be a general lack of consistency in the use and meaning of terms relating to remote measurement and remote control of the BES in the TOP, COM and PRC standards. A better glossary would ensure consistent verbiage between the standards groups. The glossary term "Telemetering" is confusingly similar to the one for "SCADA". It wrongfully includes remote control as part of the definition. We suggest it be removed from the glossary and this project.
Response: The SDT agrees with your suggestion and has changed to "telemetry." The SDT cannot change other standards that are outside the scope of this project. The commenter may submit a SAR to correct this issue in every standard that has either term present. **TOP-001-2, R6 -** Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.		
Greg Rowland	There will be no change to reliability	These revised standards (including our proposed changes), provide more clarity and will improve compliance documentation, but we don't view that as a reliability improvement. Redline Posting for TOP-001-2 has a slight different definition than the Implementation Plan for Project 2007-03: Real-Time OperationsReliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency.Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.Duke prefers the first definition. It is the one based on the definition of "Emergency" since it doesn't mention "actual or expected".
Response: The SDT has updated the Reliability Directive definition in TOP-001-2 to match the definition in the Implementation Plan and the one originally developed by the RCSDT in Project 2006-06. **Reliability Directive** — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is		

Organization	Yes or No	Question 4 Comment
necessary to address an actual or expected Emergency.		
RoLynda Shumpert	Reliability will be improved	It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: A clerical error occurred in this posting that has been corrected.		
Dominion	Reliability will be improved	While the changes remove potential ambiguity from the reliability requirements, we believe that BAs, TOPs and RCs, in almost all circumstances, understand the roles they play to insure reliable grid operations. We believe these changes are predominately the result of an increased focus on compliance related activities (audit) and industry requests for clarity. We do agree that the change in R8 is an improvement as it will allow TOP and RC to focus on the limited set of SOLs that could have an adverse impact on the BES. Dominion would also like to make a general statement concerning the VSLs for all of these standards. We are unsure as to whether the correct threshold for Low, Moderate, High and Severe is correctly identified but have no basis for a denial or suggested change. We are curious as to how the various SDTs came up with these. In some draft standards, these thresholds seem to be developed around 25% quartiles, which makes it easier to accept the high and severe categories if you consider these equivalent to a pass/fail (D or F).
Response: Regarding the VSL percentages, the SDT applied these consistent with directions from FERC that indicated that the percentage bandwidths in each severity level of a VSL should be in 5% increments. No change made.		
Northeast Power Coordinating Council	There will be no change to reliability	No change to reliability assumes that the SOLs identified as a result of the Operational Planning Analysis by the Transmission Operator as supporting its local area reliability can ensure that all the existing SOLs that are being monitored and observed (for non-exceedance) by TOPs are identified through this process. Failure to identify any such SOLs will make the system vulnerable to unreliable operation.
FirstEnergy	There will be no change to reliability	We commend the hard work of the drafting team, but find it difficult to determine if these changes will affect the reliability of the BES.
Dan Rochester	There will be no change to	Our assessment that there should be no change to reliability is made on the assumption that the SOLs identified as a result of the Operational Planning Analysis by the Transmission Operator as supporting its local area reliability can ensure that all the existing SOLs that are being monitored and observed (for non-

Organization	Yes or No	Question 4 Comment
	reliability	exceedance) by TOPs are identified through this process. Failure to identify any such SOLs will expose the system to unreliable operation.
Jonathan Appelbaum	There will be no change to reliability	The team has rationalized the existing Standards and Requirements
Terry Harbour	There will be no change to reliability	Depending upon how SOLs are implemented and enforced there could be a negative impact to system reliability as transmission outages are further restricted reducing long-term maintenance to maximize short term risks to penalties.
E.ON U.S.	There will be no change to reliability	
Midwest ISO Standards Collaborators	There will be no change to reliability	
Bonneville Power Administration	There will be no change to reliability	
PJM	There will be no change to reliability	
IRC Standards Review Committee	There will be no change to	

Organization	Yes or No	Question 4 Comment
	reliability	
Western Electricity Coordinating Council	There will be no change to reliability	
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	There will be no change to reliability	
John Fish	There will be no change to reliability	
Kasia Mihalchuk	There will be no change to reliability	
Jon Kapitz	There will be no change to reliability	
Saurabh Saksena	There will be no change to reliability	
Catherine Koch	There will be no change to	

Organization	Yes or No	Question 4 Comment
	reliability	
Michael Gammon	There will be no change to reliability	
Response: Thank you for your comment.		
PacifiCorp	Reliability will be improved	The proposed standards will improve reliability because the new standards provide a much more clear and streamlined approach than in the already approved standards. This will also enable responsible entities to focus their time on compliance with standards that improve reliability rather than be concerned with compliance with poorly written or redundant standards.
SERC OC Standards Review Group	Reliability will be improved	"The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Southern Company Transmission	Reliability will be improved	Southern's comments none SERC's comments: Southern participated in developing these comments and support them Although we feel that reliability will be improved, we cannot determine whether the language that was inserted specifically in response to order 693 is not arbitrary, capricious or otherwise deleterious to reliability.
Darryl Curtis	Reliability will be improved	
Public Service Enterprise Group Companies	Reliability will be improved	
Michael Lombardi	Reliability will be improved	

Organization	Yes or No	Question 4 Comment
Leland McMillan	Reliability will be improved	
Richard Kafka	Reliability will be improved	
Response: Thank you for your support.		
Randi Woodward		Minnesota Power does not have any comments at this time.

Consideration of Comments

Real-Time Transmission Operations — Project 2007-03

The Real-Time Transmission Operations Drafting Team thanks all commenters who submitted comments on the 5th draft and initial ballot of the standards for Real-Time Operations (Project 2007-03). The standard and associated documents were posted for a 45-day public comment period from April 26, 2011 through June 9, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special Electronic Comment Form. There were 44 sets of comments, including comments from approximately 156 different people from approximately 97 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

TOP-001-2:

- Changed the title of the standard to 'Transmission Operations' to better reflect the content of the standard.
- Based on Quality Review feedback changed the Purpose of the standard to more fully align with the requirements of the revised standard.
- Revised Requirement R1 to note that a Reliability Directive should be identified as such
- Deleted 'upon recognition' from Requirement R2
- Deleted 'all other' from Requirement R3
- Added Reliability Coordinator to Requirement R5
- Deleted Generator Operator from Requirement R6 and clarified that the requirement was for 'telemetry equipment'
- Deleted the 30 minute limit from Requirement R9 and replaced it with references to Facility Rating and Stability criteria
- Deleted the 30 minute limit from Requirement R11 to correspond with the change in Requirement R9
- Made a semantic change for clarity to Measure M2
- Changed the Time Horizons for Requirements R3, R5, and R8
- VSLs for Requirements R3, R5, and R6 were changed to move away from percentages

- The language for the VSLs in Requirements R2, R6, & R8 was clarified
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-002-3:

- Revised Requirement R2 to read as a positive statement rather than as a double negative
- Added the term "NERC" as a modifier of "registered entities" in Requirement R3
- Changed the VRF for Requirement R3 to Medium
- Modified the VSLs for Requirement R1
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-003-1:

- Based on Quality Review feedback, the Purpose of the standard has been modified to more fully align with the requirements of the revised standard.
- The bullets under Requirement R1, Part 1.1 have been deleted.
- Added new Requirement R2 to separate out the responsibilities of Balancing Authorities from Requirmeent R1.
- In response to Quality Review feedback, modified the language in Requirements R3 and R4 to clarify which data the Transmission Operator and Balancing Authority are to distribute.
- Made conforming changes to Measures to reflect changes to the Requirements.
- Based on Quality Review feedback, modified the Data Retention section to reflect the current NERC Rules of Procedure and Drafting Team Guidelines for evidence retention.
- Made conforming changes to VSLs to reflect changes to Requirements.

Other changes:

- The definition of Reliability Directive has been modified by Project 2006-06 to read as follows:

  "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts."

Minority opinions expressed at this point include:

- There is still some debate as to what is meant by internal area reliability. The SDT continues to believe, as stated in previous responses, that the Transmission Operator is best suited to determine what affects its internal area and the resolution of those issues are best left to the Transmission Operator.
- Questions arose about the role of the Balancing Authority in the actions described in the revised TOP standards. The SDT has clearly defined each element of responsibility that was previously defined for the Balancing Authority in the existing TOP standards and how it was handled in the revised TOP standards. The SDT does not believe that any gaps have been created by the revisions.
- Some commenters continue to debate the treatment of internal area reliability related SOLs in the same manner as IROLs.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Larry Rodriquez	Entegra Power	SERC	5
2.	Bill Autrey	Alabama Power	SERC	1, 3, 5
3.	Jake Miller	Dynegy	SERC	5, 6
4.	Scott Brame	NCEMCS	SERC	1, 3, 5, 9
5.	Jeff Harrison	AECI	SERC	1, 3, 5
6.	Mike Hardy	Southern	SERC	1, 3, 5
7.	Robert Thomasson	BREC	SERC	1, 3, 5, 9
8.	Chris Bolick	AECI	SERC	1, 3, 5
9.	Shardra Scott	Gulf Power	SERC	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

10.	John Troha	SERC	SERC	10

				1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	1
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	1
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1

				1	2	3	4	5	6	7	8	9	10
3.	Group	Connie Lowe	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Crowley		SERC	1
2.	Louis Slade		RFC	5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

3. Mike Garton		MRO	5, 6
4. Michael Gildea		NPCC	5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Patricia Robertson	BC Hydro	X									

Additional Member	Additional Organization	Region	Segment Selection
1. Vinnakota Venkataramakrishnan	BC Hydro	WECC	2
2. Pat G Harrington	BC Hydro	WECC	3
3. Clement Ma	BC Hydro	WECC	5
4. Daniel W O'Hearn	Powerex Corp.	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Mikhail Falkovich	Public Service Enterprise Group LLC	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Clint Bogan		NPCC	5, 6
2. Ken Brown		RFC	1
3. Jeffery Mueller		RFC	3
4. Peter Dolan		RFC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Jim Keller	Wisconsin Electric Power Company			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Linda Horn	Wisconsin Electric Power Company	RFC	5
2. Tony Jankowski	Wisconsin Electric Power Company	RFC	4

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Joe O'Brien	NIPSCO	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Kevin Largura	NIPSCO	RFC	1
2. Bill Sedoris	NIPSCO	RFC	3
3. Bill Thompson	NIPSCO	RFC	5
4. Joe O'Brien			6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tedd Snodgrass	BPA, Transmission Dispatch	WECC	1
2. Tim Loepker	BPA, Transmission Dispatch	WECC	1
3. John Anasis	BPA, Transmission Technical Operations	WECC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4. Steve Larson		BPA, Legal Office	WECC 1, 3, 5, 6										
9.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District	X		X	X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tino Zaragoza	IID	WECC	1
2.	Jesus Sammy Alcaraz	IID	WECC	3
3.	Diana Torres	IID	WECC	4
4.	Cathy Bretz	IID	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Reed	FE	RFC	1
2.	Ralph Cannon	FE	RFC	1
3.	Ken Dresner	FE	RFC	5
4.	Brian Orians	FE	RFC	5
5.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
6.	Rusty Loy	FE	RFC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Carol Gerou	MRO's NERC Standards Review Forum										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
12.	Marie Knox	Midwest ISO Inc.	MRO	2
13.	Lee Kittelson	Otter Tail Power Company	MRO	1, 3, 4, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

14.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
17.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
12.	Group	Brent Ingebrigtson	LG&E and KU Energy			X							

No additional members listed.

				1	2	3	4	5	6	7	8	9	10
13.	Group	Albert DiCaprio	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	RFC	2
2.	Patrick Brown	PJM	RFC	2
3.	Greg Campoli	NY ISO	NPCC	2
4.	Mike Falvo	IESO	NPCC	2
5.	Matt Goldberg	ISO NE	NPCC	2
6.	Kathleen Goodman	ISO NE	NPCC	2
7.	Ben Li	IESO	NPCC	2
8.	Steve Myers	ERCOT	ERCOT	2
9.	Bill Phillips	MISO	RFC	2
10.	Mark Thompson	AESO	WECC	2
11.	Mark Westendorf	MISO	RFC	2
12.	Charles Yeung	SPP	SPP	2

				1	2	3	4	5	6	7	8	9	10
14.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Electric Utility	FRCC	3

				1	2	3	4	5	6	7	8	9	10
15.	Group	Annette Bannon	PPL Supply					X	X				

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Lower Mount Bethel Energy, LLC	RFC	5										
2.	PPL Brunner Island, LLC	RFC	5										
3.	PPL Holtwood, LLC	RFC	5										
4.	PPL Martins Creek, LLC	RFC	5										
5.	PPL Montour, LLC	RFC	5										
6.	PPL Montana, LLC	WECC	5										
7.	PPL EnergyPlus, LLC	MRO	6										
8.	PPL EnergyPlus, LLC	NPCC	6										
9.	PPL EnergyPlus, LLC	RFC	6										
10.	PPL EnergyPlus, LLC	SERC	6										
11.	PPL EnergyPlus, LLC	SPP	6										
12.	PPL EnergyPlus, LLC	WECC	6										
16.	Individual	Jeff Longshore	Luminant Energy						X				
17.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
18.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
19.	Individual	Mike Laney	Luminant Power					X					
20.	Individual	Antonio Grayson	Southern Company	X		X							
21.	Individual	Chang Choi	City of Tacoma or Tacoma Public Utilities	X		X	X	X	X				
22.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
23.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
24.	Individual	Thad Ness	American Electric Power	X		X		X	X				
25.	Individual	Larry Grimm	Texas Reliability Entity										X
26.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
27.	Individual	Jim Howard	Lakeland Electric	X		X		X	X				
28.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
29.	Individual	Rex Roehl	Indeck Energy Services					X					
30.	Individual	Darryl Curtis	Oncor Electric Delivery	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
31.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
32.	Individual	David Thorne	Pepco Holdings Inc	X		X							
33.	Individual	Kirit Shah	Ameren	X		X		X	X				
34.	Individual	Anthony Jablonski	ReliabilityFirst										X
35.	Individual	Denise Lietz	Puget Sound Energy	X		X		X					
36.	Individual	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				
37.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
38.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
39.	Individual	Bill Keagle	BGE	X									
40.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
41.	Individual	Michael Moltane	ITC	X									
42.	Individual	Kathleen Goodman	ISO New England Inc.		X								
43.	Individual	Brenda Pulis	Oncor Electric Delivery	X									
44.	Individual	Michael Falvo	Independent Electricity System Operator		X								

1. **The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: In response to comments, Requirements R1, R2, R3, R5, R6, R9, and R11 were changed, along with conforming changes to the respective measures. Measure M2 was also changed in response to a specific comment. Conforming changes were made to the respective VSLs. These changes mitigated apparent double jeopardy, clarified Reliability Directives, and removed references to 30 minutes as the time limit for correcting the exceedence of an SOL.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

M2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified Reliability Directive(s) issued in accordance with Requirement R2.

M5. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5 unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

Organization	Yes or No	Question 1 Comment
Duke Energy Duke Energy Carolina	No	We disagree with the revised definition of Reliability Directive. The phrase “or expected” creates compliance uncertainty and should be struck. o R8 - We have made this comment before and continue to strongly believe that the phrase “supporting its internal area reliability” should be replaced with the phrase “having an Adverse Reliability Impact”. In the Consideration of Comments the drafting team acknowledges that the intent of the requirement is to allow a TOP to go beyond what is needed to support BES reliability, and address local load concerns. We believe such a requirement has no place in a mandatory reliability standard, because an entity can always do more than what is required. The inclusion of the concept of “supporting internal area reliability”, creates compliance risk which we believe is unnecessary and is not supported by Section 215 of the Federal Power Act. Auditors could potentially find an entity non-compliant if no SOLs have been identified

Organization	Yes or No	Question 1 Comment
		as "supporting its internal area reliability", a nebulous and undefined term. Consistent with our argument on this requirement, we also question how the drafting team was able to justify a "Medium" VRF. It very clearly doesn't meet the guidelines. o R9 - The VRF has been changed from "High" to "Medium". Consistent with our previous comment on R8, we question how the drafting team was able to justify a "High" or "Medium" VRF. It very clearly doesn't meet the guidelines. o R11 - Including the SOLs identified in R8 in this requirement effectively makes those SOLs equivalent to an IROL for mitigation purposes. Consistent with our comments above on R8 and R9, our concern is that under this approach all equipment ratings could potentially become SOLs subject to the same mitigation as IROLs.

Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for recirculation ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. The Transmission Operator may anticipate an Emergency condition without having a declared Emergency. No change made.

R8: The SDT reminds the commenter that the Transmission Operator retains responsibility for SOLs. This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase 'internal area reliability' was left undefined to encompass each of these unique challenges. No change made.

R9: The SDT believes the Medium VRF is appropriate for TOP-001-2, Requirement R9 as the SOLs that are identified by the Transmission Operator are important SOLs. To have a lower VRF, the requirement would have to be administrative in nature per the definition of VRF. No change made.

R11: The SDT agrees the subset of SOLs identified are treated the same as IROLs because they have been identified by the Transmission Operator itself as needing special treatment. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made.

Organization	Yes or No	Question 1 Comment
Ameren	No	(1)We do not agree with the definition of "Reliability Directive". The phrase "expected" Emergency creates uncertainty and will create controversy. We suggest to remove the "actual or expected" phrase, and instead add "... condition or situation that threatens the reliability of the Bulk Electric System and is likely to lead to cascading, separation, islanding, ..." after emergency consistent with the intent of the FPA and NERC Standards. (2) In R2, the SDT uses the adjective "identified" which, in the Compliance and Enforcement arena, unfortunately may imply a new and different type of Directive (an "identified Reliability Directive"). We assume the SDT meant to imply with the word "identified", that the TOP would let know the receiving party explicitly that the communication that they were receiving was in fact a Reliability Directive and not just some other form of operating communication. IF that is the case, we suggest that the SDT simply state that fact as follows, "A Directive issued by a TOP which is referred to in the ensuing 3-way communication with the recipient of that Directive using the specific words Reliability Directive". (3)In R6, we have concerns with the Generator Operator having to "notify negatively impacted interconnected NERC registered entities of planned outages of telemetry..." etc. This is too broad for a GOP to be lumped in with the TOP and BA, since most GOPs do not have the knowledge if these planned outages would negatively affect other NERC entities. We believe that R6 should apply to TOP and BA, and maybe have R6.1 that requires the GOP to notify their specific TOP and BA of planned outages of telemetry, control equipment, and communication channels which in turn would generate communication from the host TOP and BA to others so affected. (4) In R8, what is meant by "internal" area reliability? We have a significant concern form a compliance perspective about how would it be interpreted and audited. (5) R11 refers to R8 and SOL. Is it the intent of the SDT to consider SOL effectively the same as IROL for purpose of this requirement?
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. The Transmission Operator may anticipate an Emergency condition without having a declared Emergency. No change made.		

Organization	Yes or No	Question 1 Comment
The wording of Requirement R1 has been altered to add the term "identified" which will now tie to Requirement R2. **R1.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The SDT has modified Requirement R6 to eliminate the Generator Operator as TOP-003-2 covers the situation of providing this data to the Transmission Operator and Balancing Authority which are the only two entities with which the Generator Operator must communicate. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. The SDT reminds the commenter the Transmission Operator retains responsibility for SOLs. This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase 'internal area reliability' was left undefined to encompass each of these unique challenges. No change made. The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made.		
Occidental Chemical	Ballot Comment	1. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 0 Yes 1 No Comments:Ingleside Cogeneration LP agrees with most of the concepts and language the SDT is driving to in TOP-001-2. However, there are two items which we believe require further exploration before we can vote in favor of the standard. First, requirements R1 and R2 present a double-jeopardy to a GOP if a front line operator does not inform the TOP of an inability to comply with an identified Reliability Directive that violate safety, equipment, regulatory, or statutory requirements. The requirements can be modified as shown below to capture the same intent without having two high VRF assessments for the same incident. R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability

Organization	Yes or No	Question 1 Comment
		Directive issued by its Transmission Operator, [delete: unless the respective entity informs its Transmission Operator that - end delete] such actions would violate safety, equipment, regulatory, or statutory requirements. R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. Second, the concept of moving all operational data requirements - including outage notifications - to a single standard (TOP-003-1) is a useful consolidation of many similar requirements. We believe that it can be logically extended to include the notification of telemetry and control equipment outages which now fall under R6. Furthermore, TOP-003-1 requires the creation of a data specification and reporting criteria - which is far more specific than the open-ended language used in R6. 2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 Yes 0 No Comments: From a GO/GOP perspective, Ingleside Cogeneration LP agrees that a significant amount of redundancy has been removed by consolidating requirements to coordinate day-of, next-day, and seasonal operations under TOP-003. The same is true of the requirement to perform real and reactive capacity validations - which are addressed in the MOD standards. 3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 Yes 0 No Comments: Ingleside Cogeneration LP strongly supports the consolidation of TOP and BA operations data requirements into a single specification. In addition, the Project Team has correctly recognized that web-based portals and similar applications are becoming more prevalent - and should be encouraged as an effective means to distribute operations information.

Organization	Yes or No	Question 1 Comment
Response: The SDT agrees and has made changes to the requirements to address your concerns. **R1.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R2.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. The SDT has modified Requirement R6 to eliminate the Generator Operator as TOP-003-2 covers the situation of providing this data to the Transmission Operator and Balancing Authority which are the only two entities with which the Generator Operator must communicate. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
Colorado Springs Utilities	No	Colorado Springs Utilities appreciates the opportunity to comment on this draft and the changes made to this standard. The following comments are specific to requirements R3,R4, R8/R10,R9, & R11. R3. By changing "of" to "by" there is now no object to the verb "inform". Suggested language: "Each Transmission Operator shall share its assessment of its Operational Planning Analysis with its Reliability Coordinator, and all other Transmission Operators that are known or expected to be affected, based on that assessment, by actual and anticipated Emergencies." R4. Colorado Springs Utilities agrees with those who have commented on previous drafts that the language strongly implies that the TOP rendering assistance is obligated to ensure the entity receiving assistance has implemented "comparable emergency procedures." We recommend the requirement be rewritten: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Transmission Operator requested to provide such assistance may require that the requesting entity first implement its own comparable emergency procedures.” R8/R10. SOLs, which are not IROLs, by definition, do not impact interconnection reliability and should be the responsibility of the TOP, not the RC, and therefore should not require being reported to nor monitored by the

Organization	Yes or No	Question 1 Comment
		RC. R9. Does R9, as written, prevent the TOP from employing the option to permit equipment life reduction to avoid load shed? R11. Despite the SDT's clarifying comments provided during previous comment periods, this requirement continues to appear duplicative to R7 & R9 and seems to provide opportunity for double jeopardy in the event of non-compliance with one of those requirements. We suggest R11 be eliminated. If exceeding the SOL or IROL is remedied and restored within the required time frame, then the operator or the system has taken appropriate mitigating action.
Response: The suggested language for Requirement R3 was not accepted. This was the only comment on Requirement R3 from the ballot pool and the wording change is a style suggestion, not an improvement to reliability. No change made. The suggested language for Requirement R4 was not accepted. The meaning of "...provided that the requesting entity has implemented its comparable emergency procedures,…." is clear and unambiguous. No change made. Requirements R8 and R10 were added due to comments from a significant portion of the industry during the extensive posting process of these standards. The change has not been accepted. R9: This requirement is confined to that subset of SOLs that are important to internal area reliability as identified in the Operational Planning Analysis. It does not prohibit the adoption of an emergency rating that sacrifices equipment life. FAC-008-1 requires each Transmission Owner and Generator Owner to have a methodology for Facility Ratings that includes (R1.3): "Consideration of the following: R1.3.1. Ratings provided by equipment manufacturers. R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards). R1.3.3. Ambient conditions. R1.3.4. Operating limitations. R1.3.5. Other assumptions." Requirements R9 and R11 were modified to address other comments related to the 30 minute limit. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. R11: This requirement does not create double jeopardy. Requirement R11 is mandating that you take action to avoid a violation of Requirements R7 and R9. No change made.		
Cowlitz County PUD	No	Cowlitz respectfully disagrees with the SDT concerning requirements R1 and R2 addressing priori prohibitions and post-agreement to comply with an identified Reliability Directive. Cowlitz can see no Reliability difference between

Organization	Yes or No	Question 1 Comment
		an immediate "priori" and post-agreement identification of a TOP Reliability Directive action that would violate safety, equipment, regulatory, or statutory requirements. In each case the outcome is the same: the action is not complied with due to an inability to perform, and the TOP is informed "upon recognition." Therefore R1 and R2 are effectively duplicitous in this regard. Cowlitz suggests that the verbiage "...the respective entity informs its Transmission Operator that..." be removed from requirement R1. Cowlitz agrees with the SDT concerning "Reliability Directive" is not meant to equate to the urgency of a situation. This standard establishes the authority of the TOP to issue directives, and clear communication of such authority has been requested by this commenter in the past. Cowlitz applauds the SDT's stand on this issue. On all other matters, Cowlitz either agrees or abstains with the SDT.
Commonwealth of Massachusetts Department of Public Utilities	Ballot Comment	Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations] "upon recognition" seems problematic and further work needs to be done on this requirement to ensure that the proper intent is codified. The intent we believe to be "..immediately upon recognition of the inability to perform a Reliability Directive "within the stipulated or understood timeframe" would result in informing the TO. The concern exists that an entity might be able to perform the directive but may not within the proper timeframe of the TOPs need.
Response: The SDT agrees and has made changes to the requirements to address your concerns. **R1.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R2.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
Electric Market Policy	No	Dominion reads R1 to require an entity to 'carry out' the Reliability Directive. In order to comply with the requirement it must either take actions as prescribed in the Reliability Directive or it must inform the TOP that it can't do so for one of

Organization	Yes or No	Question 1 Comment
		the following: safety, equipment, regulatory or statutory requirements. It is Dominion's expectation that an entity may know whether it has safety, equipment, regulatory, or statutory conflicts with the Directive at the time the Reliability Directive is issued, but this may not always be the case (This is especially true where the Reliability Directive is issued to personnel in a control center as opposed to being directly communicated to the operator of the Element or Facility.) Regardless, whenever an entity determines it can't comply with the Reliability Directive, it must make notification or be non-compliant with R1. When the Reliability Directive has a time component and the entity doesn't comply with the time required, it is non-compliant if it hasn't completed the action(s) required unless it notified the TOP before the time component of the Reliability Directive expires (citing one of the following; safety, equipment, regulatory, or statutory requirements.) This time element guidance is not provided with this standard.
Response: R1 and R2: The SDT expects that Reliability Directives will have a time requirement. If a recipient of a Reliability Directive cannot comply due to the reasons stated in Requirement R1, then it is compliant with Requirement R1. If it does not, however, notify the issuer of its inability to comply, it is non-compliant with Requirement R2. No change made.		
Oncor Electric Delivery	No	For R6- Oncor does not believe that the proposed language will provide a coordinated communication effort in the event of a planned outages of telemetry, control equipment and associated communication channels. In addition, the term "negatively impacted interconnected registered entities" is too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity.
Response: The SDT has modified Requirement R6 to eliminate the Generator Operator as TOP-003-2 covers the situation of providing this data to the Transmission Operator and Balancing Authority which are the only two entities with which the Generator Operator must communicate. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
Southern Company Generation	Ballot	For TOP-001-2: 1) R2 and M2 are confusing due to a mismatch in using

Organization	Yes or No	Question 1 Comment
	Comment	"issued" and "identified". R2 lists the directive as "identified", while M2 lists it as "issued, identified,". It is suggested that the following phrasing be used: "an issued Reliability Directive" or "an identified Reliability Directive" 2) The use of a comma after "control equipment" in the list in R6 would make it easier to understand this requirement. (suggestion: make it match M6). 3) Please consider merging R1 and R2 into a single requirement that requires entities to comply with directives or provide a reason to the TOP why it is unable to do so. Then, the measure could be than an entity either complied or informed the TOP of its inability to comply.
Response: The language of Measure M2 was adjusted to eliminate this confusion. **M2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified Reliability Directive(s) issued in accordance with Requirement R2. The SDT agrees and changed Requirement R6: **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R1 and R2: The SDT agrees and has made changes to the requirements to address your concerns. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements **R2.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
Detroit Edison Company	Ballot Comment	I do not agree with the inclusion of the language "and negatively impacted interconnected NERC registered entities" in R6.
Response: The SDT disagrees with the broader context of your comment, but did delete the Generator Operator from this requirement. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the		

Organization	Yes or No	Question 1 Comment
affected entities.		
Grand River Dam Authority	Ballot Comment	In R8 we would ask that the words internal and area be left out completely and read as “Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its reliability based on its assessment of its Operational Planning Analysis. “
Response: The SDT considered and did not accept this change in wording. The adjectives are intended to provide guidance concerning the context of this requirement. No change made.		
Northeast Power Coordinating Council Hydro One Networks Inc.	No	In Requirement R2, there is a need to specify how much time should be allowed to “inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator.” Suggest rewording R2 to read: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall immediately inform its Transmission Operator of its inability to perform a Reliability Directive. In Requirement R4, we suggest the following rearrangement of the sentence to improve readability:R4: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures. The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which “have been identified as supporting internal area reliability” within 30 minutes should be modified to allow the TOP and RC to determine the appropriate timeframe for correcting such limits. The maintenance of Interconnection reliability and Bulk Electric System integrity is paramount, and global specifications may or may not be appropriate for a local area. Suggest modifying the appropriate wording to: within a specified time not to exceed the timeframe specified by the TOP. R9 is redundant to R11; delete R9.
Response: R2: The SDT did not accept this change. ‘Immediately’ is not a measurable quantity and would create auditing difficulties.		

Organization	Yes or No	Question 1 Comment
R4: The SDT does not agree the suggested wording improves readability. No change made. R9, R10 and R11: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. Requirement R11 is mandating that you take action to avoid a violation of Requirements R7 and R9. It is not duplicative to Requirement R9. No change made.		
Independent Electricity System Operator	No	In Requirement R2, there is a need to specify how much time should be allowed to "inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator." Suggest rewording R2 to read: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall immediately inform its Transmission Operator of its inability to perform a Reliability Directive. In Requirement R4, we suggest the following rearrangement of the sentence to improve readability:R4: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures. In Requirement R8, we suggest replacing "internal area" with "BES" for greater clarity. The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be modified to allow the TOP and RC to determine the appropriate timeframe for correcting such exceedances. We suggest the following alternative wording for Requirements R8 to R11. Additionally, we suggest removing R9 since its provisions are already covered in R11. R8. Each Transmission Operator shall inform its Reliability Coordinator of all

Organization	Yes or No	Question 1 Comment
		SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its BES reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within the time specified by the Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]

Response: R2: The SDT did not accept this change. 'Immediately' is not a measurable quantity and would create auditing difficulties.

The suggested language for Requirement R4 was not accepted. The meaning of "...provided that the requesting entity has implemented its comparable emergency procedures,...." is clear and unambiguous.

R8: "Internal area" is not intended to encompass the entire BES. The wording change was not accepted.

R9, R10 and R11: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

R9 was not deleted. This is a coordinated set of requirements: Requirement R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.

Organization	Yes or No	Question 1 Comment
Southern Company	No	It would be preferable to use the term “reliability entities” or at least replace the generic term “registered entities” with a listing of the Functional Model Entities that need to be notified. The use of registered entities would require reliability information to be given to marketing entities. R2 and M2 are confusing due to a mismatch in using “issued” and “identified”. R2 lists the directive as “identified”, while M2 lists it as “issued, identified, “. It is suggested that the following phrasing be used: “an issued Reliability Directive” or “an identified Reliability Directive”. Please consider merging R1 and R2 into a single requirement that requires entities to comply with directives or provide a reason to the TOP as to why it’s unable to do so. Then, the measure could be that an entity either complied with the requirement or informed the TOP of its inability to comply. I think R2 implies that there may be reasons other than safety, equipment, regulatory, or statutory restrictions that may prevent a Generator Operator from performing an identified Reliability Directive as it refers to the GOP’s “inability” to perform the action and doesn’t specifically reference these restrictions again. I agree with your comment that the best way to handle this would be to combine R1 and R2 into a single Requirement perhaps with the following wording:”R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity is unable to perform the actions required by the Reliability Directive (due to violation of safety, equipment, regulatory, or statutory requirements or other reasons) and informs its Transmission Operator upon recognition of its inability to perform the actions. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]” For R2, The question came up for what was more appropriate - issued or identified, and requested Reliability Directive was also suggested as an option. If the reason for this descriptive term is to clarify that the Transmission Operator has declared “this is a Reliability Directive”, then identified would be the more appropriate descriptive term and should be used in a consistent manner. For R6, we take issue with changing the wording from “telemetering equipment” to telemetry as the former is equipment and the latter implies data. The distinction is that under the current wording, the entity is required to coordinate the outage of the piece of equipment that telemeters data (i.e. the RTU) whereas the proposed change implies that the entity will have to

Organization	Yes or No	Question 1 Comment
		coordinate any outages of telemetered data. This could have significant implications as there may be 1000+ data points being telemetered by an RTU, and each data point may come from a unique piece of equipment in the plant. Is the intent that removal of, say, a pressure transmitter or a MW transducer from service for routine calibration requires notification to the Reliability Coordinator? For R6, Fleet Operations functioning as Generator Operator does not directly notify the RC, but interfaces instead with the PCC. Forwarding rules in GENcomm will deliver notifications to the RC. This impacts the evidence for M6, if the expectation is a direct communication. For R6, The use of a comma after "control equipment" in the list in R6 would make it easier to understand this requirement. (suggestion: make it match to M6). For R9, this is a duplicate requirement and does not add to reliability. This requirement is addressed in TOP-004-2 R1. For R10 and R11, these are duplicate requirements and do not add to reliability. These requirements are addressed in TOP-007-0.

Response: The SDT assumes you meant Requirement R6 in your first comment. This is not an issue if dealing with a marketing entity as it is only dealing with telemetry-related outages between the Transmission Operator or Balancing Authority and that entity itself. No change made.

The wording of Measure M2 has been altered to remove ambiguity from the use of the term "identified".

> **M2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified Reliability Directive(s) issued in accordance with Requirement R2.

R1 and R2: The SDT agrees and has made changes to the requirements to address your concerns.

> **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
>
> **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

R6: Agreed and change made.

Organization	Yes or No	Question 1 Comment
R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R9, R10 and R11 are not redundant as this project is retiring TOP-004-2 and TOP-007-0. No change made.		
ITC	No	ITC thanks the SDT for their work, and believes this iteration of the standard contains improvements. However, we have the following comments and concerns. Regarding the definition of "Reliability Directive", we believe that a clarifier should be added to indicate that a Reliability Directive is "a communication initiated AND IDENTIFIED......". The addition of the words "and identified" makes very clear that the intitiating entity must identify a communication as a Reliability Directive, and thus triggering all requirements related to the Directive. Regarding R6: ITC is concerned with the requirement that impacted "NERC registered entities" be notified of certain conditions. This puts the operating personnel in the position of having to consult the NERC Registry every time an event or action covered in this requirement occurs. Recognizing that is is not an optimal use of our operating personnel, we believe that "NERC registered" should be struck and therefore the requirement would simply require notification of "...negatively impacted interconnected entities". Regarding R8: ITC is concerned that this requirement essentially raises SOL to the same level as an IROL, which of course they should not be. We also share DECs concerns regaring this requirement that TOP actions for local reliability should not be in a mandatory reliability standard. To quote from the DEC submitted comments: "In the Consideration of Comments the drafting team acknowledges that the intent of the requirement is to allow a TOP to go beyond what is needed to support BES reliability, and address local load concerns. We believe such a requirement has no place in a mandatory reliability standard, because an entity can always do more than what is required. The inclusion of the concept of “supporting internal area reliability”, creates compliance risk which we believe is unnecessary and is not supported by Section 215 of the Federal Power Act. Auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”, a nebulous and undefined term. Consistent with our argument on this requirement, we also question how the drafting team was able to justify a “Medium” VRF. It very

Organization	Yes or No	Question 1 Comment
		clearly doesn't meet the guidelines." [End DEC comment quote]. ITC further concurs with the MRO NSRF submitted comments that "SOL's must either be removed from consideration, or more narrowly defined to the appropriate set of SOL's that directly impact the reliability of the BES (cause instability, uncontrolled seperation, or cascacing outages)."
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. No change made. R6: The SDT disagrees with the broader context of your comment, but did delete Generator Operator from this requirement. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R8: This requirement was added due to comments from a significant portion of the industry during the extensive posting process of these standards. The requirement does not elevate SOLs to the same status as IROLs, it elevates certain, selected SOLs at the discretion of the Transmission Operator based on analysis which would seem to coincide with the thoughts expressed in the comment. The change has not been accepted.		
MidAmerican Energy Co.	Ballot Comment	MidAmerican does not agree with the SDT reasoning for applying a general industry concept of 30 minutes to SOLs. The NERC standards did not call out at 30 minute time frame for SOLs and to do so equates SOLs with IROLs. The SDT should change all SOL references to IROLs or drop the 30 minute time frame. If the SDT does not elect to drop this, they should at a minimum define a subset of non-thermal SOLs that are shown by TPL or operational studies to cause instability, uncontrolled separation, or cascading as defined by the 2005 Federal Power Act. MidAmerican does not agree with the inclusion statement of non-BES assets or assets below the defined bright line 100 kV threshold. The reference should be deleted. The NERC standards apply to 100 kV and greater assets and all assets below 100 kV should be defined as distribution by default according to the 2005 FPA act definition, unless shown by TPL and operational studies to cause instability, uncontrolled separation, and cascading.

Organization	Yes or No	Question 1 Comment
		In addition, please see the MRO NSRF comments submitted

Response: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

This comment concerns TOP-003-2, Requirement R1: The SDT agrees this bullet is not necessary and made conforming changes. However, a Transmission Operator may ask for any data that is needed to support its Operational Planning Analyses and Real-time monitoring, and that could include non-BES equipment.

Organization	Yes or No	Question 1 Comment
Wisconsin Electric Power Company	No	R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator, these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase “negatively impacted interconnected NERC registered entities” is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA’s of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse Reliability Impact on another’s area, hence an emergency there is somewhat circular.

Response: R3: The suggestion was not accepted. Balancing Authorities within the Transmission Operator area are informed through TOP-002-3 as it will show in the plan. Balancing Authorities outside the Transmission Operator area will be notified by their Transmission Operator.

Organization	Yes or No	Question 1 Comment
R4: The Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made. R6: The SDT disagrees with the broader context of your comment, but did delete Generator Operator from this requirement. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R10: Balancing Authorities have no responsibility for line flows. No change made. Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]* **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*		
Imperial Irrigation District	Yes	R5 - should include notification of the Reliability Coordinator involvingAdverse Reliability ImpactM1 (b) - did not comply with the indentified directive and informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1.M5 - include the notification to the Reliability Coordinator known or expected to result in an Adverse Reliability Impact Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5
Response: R5: Suggestion was accepted and the requirement and measure were modified accordingly. **R5**. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such		

Organization	Yes or No	Question 1 Comment
communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. **M5**. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5 unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.		
City of Green Cove Springs	Ballot Comment	R5 seems to limit communications / coordination more than the version 1 standard (old R7) to only those actions that can result in an Adverse Reliability Impact, which are very few. GCS suggests adding the phrase "or cause an SOL or IROL to be exceeded" to the requirements, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact or cause an SOL or IROL to be exceeded on those respective Transmission Operator Areas ...." R7 is ambiguous as to whether the IROL and IROL Tv are IROLs identified in real-time or identified through Operational Planning Analysis. R7 should be treated in a similar manner to R9 and refer to those IROLs identified through the Operational Planning Analysis. The concern is that if an extreme contingency occurs beyond what is in the scope of the Operational Planning Analysis, and that extreme contingency causes an IROL with a very short Tv in real-time, will the TOP be able to comply? R8 belongs in TOP-002-3 since it is Operational Planning Analysis. R11 seems to create double jeopardy with R7 and R9. R11 should be deleted and the concepts embedded in R11, such as "direct others" and "limit the magnitude and duration", ought to be included in R7 and R9 instead. The prior version 2 standard was applicable to both the BA and the TOP. The new standard is just the TOP, which is appropriate; however, it was the old TOP-002-1 that basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed to meet the next day's peak load plus contingency reserve requirements, frequency reserves and regulation service (at least that's how we interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). BAL-002-0 requires that a BA have enough contingency reserves, but, it is unclear as to whether a BA is permitted to shed load to achieve those reserves, and how regulation service

Organization	Yes or No	Question 1 Comment
		and frequency reserves are handled.
Response: R5: The suggested language was not included as it is redundant. The Transmission Operator is not likely to know exactly which conditions on its system may cause an IROL or SOL excursion on a neighboring system and is not responsible for the neighboring Transmission Operator systems. The proposed TOP-003-2 requires a data specification that would cover the line flow and limit data necessary for the neighboring Transmission Operator to assure reliability in its area. R7: An IROL that emerges in real-time may not have been identified in the Operational Planning Analysis. If you don't know about it, you can't control it and wouldn't be responsible. Requirement R8 covers those IROLs that can be anticipated. No change made. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R11: This is a coordinated set of requirements: Requirement R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation. No change made. Regarding the removal of the Balancing Authority from Requirements R5, R6, and R7: The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2. The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.		
Alberta Electric System Operator	Ballot Comment	The AESO believes requirements (R9 and R11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary

Organization	Yes or No	Question 1 Comment
		rating and timing associated with each of the ratings. The AESO would also like to see the term "emergency assistance", used in R4, defined.
Response: Requirements R9 and R11: Agreed and changed. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. R4: "Emergency assistance", similar to the data specification in TOP-003-2, should not be limited to an arbitrary list included in a requirement. If the Transmission Operator has any tool, method, or solution that can be used to provide emergency assistance to a neighboring Transmission Operator, it should. For example. the Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made.		
Constellation Energy Commodities Group	Ballot Comment	The definition of Reliability Directive needs to include: The RC, TOP or BA must clearly state that "This is a Reliability Directive". This would also apply to project 2006-06.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. No change made.		
American Electric Power	No	The draft of R6 states that "Each Transmission Operator, Balancing Authority, and Generator Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetry, control equipment and associated communication channels between the affected entities." The assessment and dissemination of GOP info to the "affected entities" should be the responsibility of the local TOP and RC. It seems inappropriate to request that the GOP make these sorts of contacts, as GOPs would lack the necessary BES info to make a determination as to who should be notified.
Response: Agreed and changed.		

Organization	Yes or No	Question 1 Comment
R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
Independent Electricity System Operator	Ballot Comment	The IESO respectfully submits the following comments along with our negative vote: 1. TOP-001-2 Requirement R2: This requires each listed entity to “inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator .” We consider “upon recognition” to be unclear since there is no indication whether the expectation is for entities to inform the TOP immediately or within some defined time. We therefore suggest the alternative wording “ immediately inform its Transmission Operator of its inability to perform a Reliability Directive.” This wording, while still not perfect does convey an expectation regarding the timeliness of the entity’s communication with the TOP. 2. TOP-001-2 Requirement R9 and R11: These set time limits within which exceedances of IROLs and SOLs indentified pursuant to Requirement R8 must be mitigated, Tv in the case of IROLs and 30 minutes in the case of SOLs. We believe prescribing 30 minutes is not appropriate for SOLs identified in R8 and suggest rewording R8, R10 and R11 as indicated below. Additionally, we suggest removing R9 since its provisions are already covered in R11. In Requirement R8, we suggest replacing “internal area” with “BES” for greater clarity. R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its BES reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s Tv, or of an SOL identified in Requirement R8 within the time specified by the

Organization	Yes or No	Question 1 Comment
		Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]

Response: R2: Agreed. Requirements R1 and R2 were modified.

> **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
>
> **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

R8: "Internal area" is not intended to encompass the entire BES. The wording change was not accepted.

R9, R10 and R11: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

> **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
>
> **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

Requirement R9 was not deleted. This is a coordinated set of requirements: R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.

Requirement R9 is not redundant (see above). No change made.

Organization	Yes or No	Question 1 Comment
Northern Indiana Public Service Co.	Ballot Comment	The new standard appears to treat SOLs and IROLs in a similar manner, which should not be the case. Also, in TOP-003-2 R1 1.1 the second bullet may incorrectly bring non-BES

Organization	Yes or No	Question 1 Comment
		distribution facilities into play.
Response: R11: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made. This comment concerns TOP-003-2, Requirement R1: The SDT agrees this bullet is not necessary and made conforming changes. However, a Transmission Operator may ask for any data that is needed to support its Operational Planning Analyses and Real-time monitoring, and that could include non-BES equipment.		
ISO/RTO Standards Review Committee	No	The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. The SRC proposes the following changes:R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] Delete the following requirement entirely--- R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] new R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] new R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within [DELETE 30 minutes] the time specified by the Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations] There doesn't seem to be a need for R9 since this is covered in R11.
ISO New England Inc.	No	The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have

Organization	Yes or No	Question 1 Comment
		been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. We propose the following changes: R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. Delete the following requirement entirely--- R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.---There doesn't seem to be a need for this is covered in R11. Formerly R10, new R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. Formerly R11, new R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within [DELETE 30 minutes] the time specified by the Transmission Operator.

Response: R8: The language was considered but not accepted; however, Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees that the 30 minute limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

> **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
>
> **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

Requirement R9 was not deleted. This is a coordinated set of requirements: R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11) , and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.

Organization	Yes or No	Question 1 Comment
Southwest Power Pool	Ballot Comment	The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. The SRC proposes the following changes: R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Delete in entirety Renumber R10 to R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]
Response: R8: The language was considered but not accepted; however, Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. Requirement R9 was not deleted. This is a coordinated set of requirements: R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.		
Texas Reliability Entity	No	The statement "identified reliability directive" in R1 and R2, of standard TOP-001-2, would be better changed to "reliability directive." The word "identify" requires action and the standard does not specify how the "identifying " will be done. Furthermore, if the TOP is issuing a directive, it should be assumed that the

Organization	Yes or No	Question 1 Comment
		directive is a Reliability Directive unless the TOP states that it is not. This position saves time when time is of the utmost importance. The proposed wording as presented will open the door for deliberation when corrective action should be well underway.
Response: The language in Requirement R1 was altered to reduce the possibility of confusion over the word "identified". **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The other suggested changes for Requirement R1 were not accepted. The Reliability Directive was crafted to require positive identification. When time is of utmost importance, it is better for reliability to get the communications exactly right the first time.		
Great River Energy	Ballot Comment	This requirement has the potential of treating SOLs as an IROL
Response: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made.		
James A Maenner	Ballot Comment	TOP-001 R1 "identified Reliability Directive" is subjective and vague; needs to be clearer. TOP-001 R11 is troubling; it seems to elevate SOLs to IROL status. TOP-001 The language "or expected" allows too many variants; better language maybe "as indicated through system or operational studies". The language "internal area reliability" may lead to an interpretation issue and should be defined.
Response: R1: The language was changed to clarify the intent. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.		

Organization	Yes or No	Question 1 Comment
R11: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made. The requirement was not identified in the comments. Presumably this comment concerned Requirement R3. The SDT considered the suggested language but did not accept it because it does not add clarity. R8: This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase 'internal area reliability' was left undefined to encompass each of these unique challenges. No change made.		
New Brunswick Power Transmission Corporation	Ballot Comment	TOP-001 R11: "within 30 minutes" should be specified by the transmisison operator or owner. TOP-003 R1:"at voltage levels lower than the BES;" should be removed or justified on a case by case basis.
Response: Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. This comment concerns TOP-003-2, Requirement R1: The SDT agrees this bullet is not necessary and made conforming changes. However, a Transmission Operator may ask for any data that is needed to support its Operational Planning Analyses and Real-time monitoring, and that could include non-BES equipment.		
Wisconsin Electric Power Marketing, Wisconsin Electric Power Co.	Ballot Comment	TOP-001 R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator,

Organization	Yes or No	Question 1 Comment
		these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase “negatively impacted interconnected NERC registered entities” is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA’s of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse Reliability Impact on another’s area, hence an emergency there is somewhat circular.

Response: R3: The suggestion was not accepted. Balancing Authorities within the Transmission Operator area are informed through TOP-002-3 as it will show in the plan. Balancing Authorities outside the Transmission Operator area will be notified by their Transmission Operator. No change made.

R4: The Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made.

R6: The SDT disagrees with the broader context of your comment, but did delete the Generator Operator from this requirement.

> **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.

R10: Balancing Authorities have no responsibility for line flows. No change made.

Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this.

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

Organization	Yes or No	Question 1 Comment
R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*		
Lakeland Electric	No	TOP-001-2 Coordination of Transmission Operations R5 seems to limit communications / coordination more than the version 1 standard (old R7) to only those actions that can result in an Adverse Reliability Impact, which are very few. This is probably underperforming and FERC will probably not like it. Some other limits to the scope of communications, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations of Bulk Electric System Facilities known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load." I disagree with deleting TOP-008-1 R3 that allows TOPs, after exhausting other methods to alleviate the problem, to open a Facility if it is imminent danger of catastrophic failure. The requirement should be revised and included in TOP-001-2 as something like the TOP shall request permission of the RC to disconnect the Facility if there is a threat of imminent catastrophic failure, the RC can direct otherwise "unless the direction per Requirement (IRO-001-2). R2 can not be implemented or such actions would violate safety, equipment, regulatory or statutory requirements" (IRO-001-2, R3). Exceeding an IROL that might result in a system restoration event with equipment capable of being restored is preferable to waiting for a Facility to be disconnected due to catastrophic failure, still exceeding the IROL due to that disconnection, but resulting in a system restoration exercise with catastrophically failed equipment. An example of this is the 1977 blackout of NYC which was exacerbated by catastrophically failed equipment. On R7 and R9, I'm concerned about the "for how many contingencies" question, e.g., are we held to the same criteria for "extreme contingencies"? The BAL standards have exclusions for multiple contingencies in meeting the performance requirements (e.g.,BAL-002-0 D1.4). There is not such consideration for "Extreme" contingencies in R7 and R9. If a bad event occurs beyond the criteria we operate the system to, are we setting ourselves up for failure and fines?

Organization	Yes or No	Question 1 Comment
Response: The suggested language was not included as it is redundant. The Transmission Operator is not likely to know exactly which conditions on its system may cause an IROL or SOL excursion on a neighboring system and is not responsible for the neighboring Transmission Operator system. The proposed TOP-003-2 requires a data specification that would cover the line flow and limit data necessary for the neighboring Transmission Operator to assure reliability in its area. Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. The SDT reaffirms that a standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse. No change made. Requirements R7 and R9 simply state you must not operate outside IROLs and the non-IROL SOL subset. They do not define how IROLs and SOLs get created. Creation of IROLs and SOLs is governed by FAC-011-2 and FAC-014-2. FAC-011-2 establishes how contingencies must be considered including if any multiple contingencies (FAC-011-2 R3.3) must be included. No change made.		
Northeast Power Coordinating Council, Inc.	Ballot Comment	TOP-001-2 R2 states: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations] "upon recognition" seems problematic and further work needs to be done on this requirement to ensure that the proper intent is codified. The intent we believe to be "..immediately upon recognition of the inability to perform a Reliability Directive "within the stipulated or understood timeframe" would result in informing the TO. The concern exists that an entity might be able to perform the directive but may not within the proper timeframe of the TOPs need.
Response: The SDT modified Requirements R1 and R2. However, 'immediately' is not a measurable quantity and would create auditing difficulties. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
New Brunswick System Operator	Ballot Comment	TOP-001-2 R9, 10 and 11 that stipulates returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be

Organization	Yes or No	Question 1 Comment
		modified to allow the TOP and RC to determine the appropriate time frame for correcting such limits.
Response: Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.		
Lakeland Electric	Ballot Comment	TOP-001-2 The words “that are known or expected to be affected” in R3 and “known or expected to result” in R5 may seem reasonable until you look at the VSL table and question the risk of have a PV because the TOP overlooked a notification of marginal value under these requirements in the heat of battle because the condition was not expected to impact an entity.
Response: The Operational Planning Analysis points to those “expected to be affected.” No change made.		
South Texas Electric Cooperative	Ballot Comment	TOPs should not be expected to notify other TOPs of problems. That should be the responsibility of the RC or the BA - whomever the TOP is reporting to should have the responsibility of consolidating reports and notifying affected entities accordingly.
Response: The Transmission Operator must coordinate with its neighbors. This is the lynchpin of coordinated operations. No change made.		
Consumers Energy	Ballot Comment	We concur with most of Duke Energy's comments. We further add that we are especially concerned with the definition of Reliability Directive which is ambiguous at best. In TOP-001-2, R2 there is a statement of "upon recognition" in dealing the informing the TO of an inability to follow a Reliability Directive. This is vague and very difficult to document. It is unfortunate but the transition to legalistic interpretations of standards, a task often defaulting to audit team personnel, makes it absolutely mandatory that the expectations for proof of compliance be improved to be totally clear.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition.		

Organization	Yes or No	Question 1 Comment
Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. The Transmission Operator may anticipate an Emergency condition without having a declared Emergency. No change made. R2: This language was deleted. **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
MRO's NERC Standards Review Forum	No	We disagree with the statement in R8 ". . . have been identified by the Transmission Operator as supporting its internal area reliability . . .". This statement puts an SOL on the same level as an IROL, which is not the intent of an SOL. The Transmission Operator should inform the Reliability Coordinator of IROL's that may impact the reliability of the BES, but not SOL's. R9 - We continue to believe that SOL's should not be a part of the TOP-001-2 standard. There are not identified timeframes in the NERC standards that apply to SOL's. There has been no basis for the 30 minute timeframe listed, as "generally accepted by the industry" is not a technical basis, and SOL's are often tied to thermal limits and other steps can be taken locally to offset the SOL. If SOL's must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded. An example definition might be "non-thermal SOL's are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability."Including SOL's in R11 effectively makes them equivalent to IROL's for mitigation purposes. Consistent with our comments in R8 and R9, SOL's must either be removed from consideration, or more narrowly defined to the appropriate set of SOL's that directly impact the reliability of the BES (cause instability, uncontrolled separation, or cascading outages). The SDT should ensure that TOP-001 consistent with FAC-014-2 R2 concerning identification of SOLs.
Response: R8: The SDT agrees the subset of SOLs identified are treated the same as IROLs because they have been identified by the Transmission Operator itself as needing special treatment. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made. Requirements R9 and R11 were modified to address other comments related to the 30 minute limit. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous		

Organization	Yes or No	Question 1 Comment
duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.		
FirstEnergy	No	We have the following comments and suggestions:1. R3 - Since this requirement is describing actions to be taken in Real-time as shown in the Time Horizon, the use of the term "Operational Planning Analysis" may not be appropriate. This is because an analysis in the operations planning timeframe is restricted to next day and up to 12 months in the future. We suggest that the team reconsider of the use of this phrase and remove the last part of this requirement, specifically remove "based on its assessment of its Operational Planning Analysis". 2. R6 - We do not agree with the phrase "and negatively impacted interconnected NERC registered entities". We believe that it should be the responsibility of the Reliability Coordinator to notify all impacted entities since they are afforded the wide-area view of the area. 3. R6 - The phrase "control equipment" is too broad and lacking clarity with regard to the phrase "between the affected entities". We suggest that additional clarification be added by providing examples of the types of control equipment or the loss of functionality that could occur due to the outage.
Response: Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]* **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]* R6: The SDT does not agree that Transmission Operators should not coordinate with neighboring Transmission Operators. The phrase 'negatively impacted interconnected NERC registered entities' was arrived at over multiple postings with industry – no change made. However, other changes were made in Requirement R6 to help with clarity.		

Organization	Yes or No	Question 1 Comment
R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
East Kentucky Power Coop. Southwest Transmission Cooperative, Inc.	Ballot Comment	We thank the standards drafting team for their efforts in drafting this set of standards and believe they are significantly improved over the existing standards. We have identified some issues that warrant additional consideration by the drafting team. While TOP-001-2 R8 is an improvement of the existing TOP-004-2 R1, it introduces new ambiguity into the standards. What criteria should the TOP use for identifying the subset of non-IROL SOLs? If the TOP has a procedure/process document that defines how it identifies these SOLs and follows that procedure/process, will it be compliant with the requirement? Can the TOP ever be second-guessed on its list? The clause "that represents projected System conditions" is redundant with the definition of Operational Planning Analysis in TOP-002-3 R1. To avoid confusion, TOP-002-3 R2 should reference that the SOLs are those identified in TOP-001-2 R8 similar to how TOP-001-2 R11 references it.
Response: This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase 'internal area reliability' was left undefined to encompass each of these unique challenges. The SDT believes the Transmission Operator cannot be second-guessed on this list. No change made. The SDT considered deletion of this phrase; however, it provides clarity for this requirement and does not introduce ambiguities. No change made. The SDT agrees and has made conforming changes to TOP-002-3, Requirement R2.		
LG&E and KU Energy PPL Supply	No	While LG&E and KU Energy generally agrees with the changes that were made, we do not feel the standard is ready for balloting based on the following comments:R1 and R2 - In both requirements, notification of the TOP is required and appears to be for the same condition. If this is not so, the requirements need to be more specific regarding the reasons for notification. For example, R1 appears to require notification for specific conditions regarding violations of

Organization	Yes or No	Question 1 Comment
		safety, equipment, regulatory or statutory requirements and R2 could be interpreted that after agreeing to and during the course of complying with a reliability directive, the entity was unable to do so. LG&E and KU Energy does not believe that these two requirements need to be separated.Moreover, to the extent there are duplicative requirements for the same issue, if a violation were to occur, an entity may be in violation of two requirements instead of one. The standards must clearly state what is required and must do so without creating duplicative or overlapping requirements or sub-requirements. As presently drafted, R1 and R2 create confusion as to what is required and could result in multiple self reports for the same potential violation and potentially additional penalties as a result of two violations for what appears to be the same issue. R3 - This requirement appears to be an operational planning requirement and may more appropriately be inserted in TOP-002-3. If it remains in this standard, we suggest the following wording: Each TOP shall inform its RC and all other TOPs that are expected to be affected by anticipated emergencies based on its operational planning analysis. LG&E and KU Energy thinks “assessment” is synonymous with “analysis”). We also believe that R5 is intended to cover real-time operations. The time horizons do not appear to match the requirement, i.e., Operations Planning. R4 - No comments R5 - LG&E and KU Energy recommend similar language to that in R3 for consistency and clarity, i.e., R3 has “all other transmission operators” and R5 has “other Transmission Operators”. The requirement is unclear in describing who is responsible for informing whom, needs to be rewritten to clarify. R6 - What is meant by “associated communication channels”? Data or Voice or both? Is this not covered by the COM Standards? Additionally, please clarify what is intended by terms “negatively impacted interconnected NERC entities” and “control equipment” as used in proposed R6. R7 - No comments R8 - The use of Operational Planning Analysis in this requirement is not consistent with the Time Horizon of Real-time Operations. Based on the NERC definition Operational Planning Analysis is considered future looking (next-day through 12 months) this would exclude modification to SOLs made during Real-time Operations.SOLs utilized in Operational Planning Analysis are based on certain assumptions given forecasted conditions or historical data. Real-time operating conditions can vary drastically from these assumptions and there

Organization	Yes or No	Question 1 Comment
		needs to be flexibility in modifying SOLs to account for these actual system conditions. R9 - The 30 minute duration is quite restrictive in resolving an SOL exceedance, especially for those that are considered to support internal area reliability. Does this apply only to actual SOL exceedances, or does it also include post-contingent SOL exceedances? LG&E and KU Energy feel the time limit should be at least 90 minutes for exceeding an SOL (especially for post-contingent SOLs), to allow for use of TLR procedures or other measures which often take more than 30 minutes to implement.There needs to be some flexibility in establishing Real-time Operations SOLs based on actual system conditions separate from the Operational Planning Analysis. R10 - Because the Time Horizon is “Real-time Operations” the SOLs communicated to the RC per this requirement should be the Real-time Operations established SOLs, not the Operational Planning Analysis SOLs established in R8. R11 - The SOLs established in R8 deal with future looking Operational Planning Analysis, however this requirement deals with Real-time Operations. Need clarification about Real-time Operations SOLs and we suggest the time duration for SOLs exceedances should be at least 90 minutes as described in R9.

Response: The SDT agrees and has made changes to the requirements to address your concerns.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. Language has been changed to make Requirement R3 consistent with Requirement R5.

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or

Organization	Yes or No	Question 1 Comment
expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]* R6: The COM standards cover voice only. The terminology used in Requirement R6 is well understood. No change made for this comment. The phrase 'negatively impacted interconnected NERC registered entities' was arrived at over multiple postings with industry – no change made. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R10 – For SOLs discovered in real-time, the Transmission Operator doesn't need to inform as it is an SOL and hasn't been previously reported to the Reliability Coordinator. No change made. R9 and R11: Agreed and language changed to reflect the intent of the suggested changes. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.		
SERC OC Standards Review Group	No	While we generally agree with the changes that were made, we do not feel the standard is ready for balloting based on the following comments:R1 and R2 - In both requirements, notification of the TOP is required and appears to be for the same condition. If this is not so, the requirements need to be more specific regarding the reasons for notification. For example, R1 appears to require notification for specific conditions regarding violations of safety, equipment, regulatory or statutory requirements and R2 could be interpreted that after agreeing to and during the course of complying with a reliability directive, the entity was unable to do so. The group does not feel that these two requirements need to be separated. R3 - This requirement appears to be an operational planning requirement and may more appropriately be inserted in TOP-002-3. If it remains in this standard, we suggest the following wording: Each TOP shall inform its RC and all other TOPs that are expected to be affected by anticipated emergencies based on its operational planning analysis. (We think "assessment" is synonymous with "analysis"). We also believe that R5 is intended to cover real-time operations. The time horizons do not appear to match the requirement, i.e., Operations Planning.

Organization	Yes or No	Question 1 Comment
		R4 - No comments R5 - We recommend similar language to that in R3 for consistency and clarity, i.e., R3 has “all other transmission operators” and R5 has “other Transmission Operators”. R6 - What is meant by “associated communication channels”? Data or Voice or both? Is this not covered by the COM Standards? R7 - No comments R8 - The use of Operational Planning Analysis in this requirement is not consistent with the Time Horizon of Real-time Operations. R9 - We feel the time limit should be 90 minutes for exceeding an SOL, to allow for use of TLR procedures or other measures. R10 and R11 - Logically these two requirements should be swapped so that the requirement to act is performed prior to notification of actions taken. The reference to 30 minutes should be changed to 90 minutes (see comment to R9 above).

Response: The SDT agrees and has made changes to the requirements to address your concerns.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. Language has been changed to make Requirement R3 consistent with Requirement R5.

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*

Organization	Yes or No	Question 1 Comment
R6: The COM standards cover voice only. The terminology used in Requirement R6 is well understood. No change made for this comment. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R9 and R11: Agreed – the 30 minute time limit was deleted. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. R10 – The requirements are not sequential. No change made.		
Progress Energy	No	
Response: Without specific comments, the SDT is unable to respond.		
Florida Municipal Power Agency	No	R5 requires communications / coordination more than the version 1 standard (old R7) to those actions that can result in an Adverse Reliability Impact, which are very few and is ambiguous. FMPA suggests adding the phrase "or cause an SOL or IROL to be exceeded" to the requirements, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact or cause an SOL or IROL to be exceeded on those respective Transmission Operator Areas ...." Also, there seems to be overlap of responsibility with the RC in real-time operations concerning SOLs and IROLs. FMPA can certainly see informing the RC and neighboring TOPs of a potential SOL / IROL in an Operational Planning Assessment, but, in real-time, that may be too much of a burden and might step on the RC's toes in efficient and effective communication and coordination. R7 is ambiguous as to whether the IROL and IROL Tv are IROLs identified in real-time or identified through Operational Planning Analysis. R7 should be treated in a similar manner to R9 and refer to those IROLs identified through the Operational Planning Analysis. The concern is that if an extreme contingency occurs beyond what is in the scope of the Operational Planning Analysis, and that extreme contingency causes an IROL with a very short Tv in real-time, will the TOP be able to comply?

Organization	Yes or No	Question 1 Comment
		R8 belongs in TOP-002-3 since it is Operational Planning Analysis. R11 seems to create double jeopardy with R7 and R9. R11 should be deleted and the concepts embedded in R11, such as “direct others” and “limit the magnitude and duration”, ought to be included in R7 and R9 instead.
Response: R5 – The language of Requirement R5 was changed due to comments from others and it now provides better clarity as to the SDT’s intent. **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. The SDT does not see an overlap. The Transmission Operator is responsible for all SOLs and for informing the Reliability Coordinator of the subset of SOLs that will receive greater scrutiny. No change made. R7: An IROL that emerges in real-time may not have been identified in the Operational Planning Analysis. If you don’t know about it, you can’t control it and wouldn’t be responsible. Requirement R8 covers those IROLs that can be anticipated. No change made. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R11: This requirement does not create double jeopardy. Requirement R11 is mandating that you take action to avoid a violation of Requirements R7 and R9. No change made.		
Manitoba Hydro	Yes	The term ‘reliability entity’ used in TOP-001-02 should be changed to ‘registered entity’.
Response: The SDT reviewed TOP-001-2 and could not locate any instances of “reliability entity” to change. “Registered entities” was used in Requirement R6.		
Northeast Utilities	Yes	Suggest rearranging R4 to read: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures.
Response: The SDT considered this suggestion but did not accept it. This change does not add clarity. No change made.		
Pepco Holdings Inc	Yes	Should the standard be applicable to a TO? Specially it would appear that R1 and R2 should be applicable to a TO in addition to the other listed entities.

Organization	Yes or No	Question 1 Comment
Response: All transmission facilities must have a Transmission Operator. This applies to operators not owners.		
BGE	Yes	Comment on proposed TOP-001-2 Reliability Directive definition: Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency.This needs to also include: The RC, TOP or BA must clearly state that “This is a Reliability Directive”.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. No change made.		
City of Tacoma or Tacoma Public Utilities	Yes	1. The Standard Development Roadmap, page 2, states there are no new or revised definitions yet there is a revised definition for “Reliability Directive.” Reliability Directive is not listed in NERC’s Glossary of Terms. 2. The terms “Operational Planning”, “Same Day Operations” and Real-time Operations” need definitions that include a time horizon. 3. R1: The language is redundant with R2. Removing “...the respective entity informs its Transmission Operator that...” from R1 would eliminate the redundancy. 4. R5: New R5 language replaces the old language from TOP-001-2 R 7.3.Proposed: “Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, transmission or load.”Existing R7, R.3:”When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generation Operator shall notify the Transmission Operator and the Transmission Operator shall notify its Reliability Coordinator and adjacent Balancing Authority, at the earliest possible time.”Suggestion - Include language to identify the time requirement for communications including after-the-fact notifications. The purpose of the requirement is to inform, yet there is no associated timeframe. 1. R10: Similar to R5, this requirement also needs an associated timeframe to

Organization	Yes or No	Question 1 Comment
		inform the RC, otherwise it's difficult to measure.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. It is shown here for the reviewer's convenience. No change made. Time Horizons are defined at NERC: http://www.nerc.com/files/Time_Horizons.pdf R1: Agreed and conforming changes were made. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. R5 & R10: There is no definable timeframe for all conditions consistently and objectively measurable. No change made.		
BC Hydro	Yes	
Bonneville Power Administration	Yes	
Luminant Energy	Yes	
Western Electricity Coordinating Council	Yes	
Luminant Power	Yes	
Indeck Energy Services	Yes	
ReliabilityFirst	Yes	
Puget Sound Energy	Yes	
Georgia Transmission Corporation	Yes	
Response: Thank you for your support.		

2. **The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The SDT made a few minor clarifying changes in response to comments received. The SDT does not consider the changes to be substantive.

The SDT revised Requirement R2 of TOP-002-3 to read as a positive statement rather than as a double negative. The change is simply a restatement without changing the meaning of the requirement, but should be clearer now.

A few commenters were concerned with the use of what they believed to be a definition that is not included in the Glossary of Terms used in NERC Reliability Standards. The definition of concern is that of Operational Planning Analysis. The definition is in the glossary, so the SDT doesn't understand the comments and no change was made.

The SDT made a clarifying change to Requirement R3 of TOP-002-3 by adding the term "NERC" as a modifier of "registered entities".

The SDT made revisions in TOP-001-2 to clarify the time relating to the exceedance of the subset of SOLs that, while not IROLs, has been identified by the Transmission Operator as supporting its internal area reliability. Concerns were expressed that 30 minutes was not applicable to all SOLs. The SDT agrees and has made the clarifying changes.

Some commenters were concerned with the notifications indicated in Requirement R3 for entities identified in an operating plan. Some of the commenters said it could be read to mean all entities have to be notified. The SDT reviewed the comments and the wording and did not agree that the language needed to be changed. The standard describes "what" must be done; namely, review and plan how to address predicted exceedances, but does not specify "how" to do the plan, which would be unnecessarily prescriptive. When the Transmission Operator performs its planning activities, those entities identified as having a role in the mitigating actions are identified. It is only those entities that will have a role in the execution of the plan that must be notified.

R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their

role in those plan(s).

Organization	Yes or No	Question 2 Comment
City of Tacoma or Tacoma Public Utilities	No	R2: “Each Transmission Operator shall plan to preclude operating in excess of Interconnected reliability Limits (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified as supporting its internal area reliability, as a result of the Operational Planning Analysis performed in Requirement R1.”Suggestion - The statement in red is a double negative and difficult to follow. Rewrite this sentence to be a positive statement to avoid confusion, for example, “Each Transmission operator shall plan to operate within identified ...”
Response: The SDT agrees and has revised Requirement R2. **R2.** Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Duke Energy Duke Energy Carolina	No	This standard uses the capitalized term “Operational Planning Analysis” which is not currently a NERC defined term. How is this to be applied in the standard? o R2 - We reiterate our comments on TOP-001-2 regarding the problematic phrase “supporting its internal area reliability”. Will an entity’s Operational Planning Analysis be found deficient if no SOLs have been identified which support “internal area reliability”? We believe that it is certainly possible. Furthermore, in M2, what evidence will be required to be presented to demonstrate that an entity has no SOLs which “support internal area reliability”? o R3 - insert the word “NERC” before the word “registered” to add clarity.
Response: The term “Operational Planning Analysis” is in the Glossary of Terms used in NERC Reliability Standards. No change made. The SDT reminds you the Transmission Operator has primary responsibility for all System Operating Limits (SOLs) within its purview (or footprint or area). The requirement is for the Transmission Operator to decide which of its SOLs rise to a greater degree of importance to its internal area reliability such that the Transmission Operator wishes the Reliability Coordinator to join in monitoring and controlling system parameters within the SOL(s). If the Transmission Operator does not believe it has any such SOLs, it is not required to notify the Reliability Coordinator of any. No change made.		

Organization	Yes or No	Question 2 Comment
The SDT has added the word "NERC" to provide clarification. **R3**. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).		
Ameren	No	(1)R1 refers to "Operational Planning Analysis" which is not a defined term. Similarly, R3 uses the phrase "registered entities identified in the plan(s) cited in R2 which is confusing. Please define/clarify these terms or phrases. (2) In R2 (similar to R8 in TOP-001-2) , what is meant by "internal" area reliability? We have a significant concern form a compliance perspective about how would it be interpreted and audited.
Response: The term "Operational Planning Analysis" is in the Glossary of Terms used in NERC Reliability Standards. No change made. The SDT reviewed the questioned language and, after discussion, does not understand what is causing the confusion. No change made. The SDT changed "local area" to "internal area" based upon comments received from the industry. While all SOLs are relevant for only localized issues, not widespread BES issues, each Transmission Operator has a Transmission Operator area within which it has primary reliability responsibilities. The SDT believes that area is its "internal area" and does not involve crossing boundaries or affecting other Transmission Operator area(s). No change made.		
MRO's NERC Standards Review Forum	No	believes that the boundaries are not identified in TOP-002-3 R2. For IROLs, the boundaries should be limited to the Registered Entities footprint.
Response: The SDT disagrees. IROLs definitely may involve crossing boundaries between registered entities' footprints. Operations within one area may affect system flows or other parameters within other areas, or the limits may be on interconnecting facilities. Typically the Transmission Operator has the most granular and specific information for the system facilities within its area, but the Reliability Coordinator has a widespread view, albeit that it may be at a higher level and less granular. The plans of the Transmission Operator that are relevant to Requirement R2 are those plans the Transmission Operator will implement to ensure operating actions within the IROLs and SOLs. The Transmission Operator is also required to notify other entities which will have a role in the execution of those plans. Therefore, there are many different potential combinations of areas and boundaries and possible interconnecting facilities between areas that may be involved in such operating action plans. No change made.		
Electric Market Policy	No	Dominion is unsure as to which version (clean or redline) of the language in the grey box (for R1) the SDT intended. The sentence (in red line version) appears to read "Rationale for Requirement R1: Operational Planning Analysis (OPA) does not the analysis even if those

Organization	Yes or No	Question 2 Comment
		tools are not available." Please clarify. We also did not find any changes to the Data Retention (red line version).
Response: The clean version is the correct version.		
City of Green Cove Springs Florida Municipal Power Agency	Ballot Comment	GCS still believes that unit commitment needs to be covered better when moving from the old TOP standards to the new TOP standards. Yes, unit commitment is a BA function, not a TOP function, and yes, BAL-002 does cover a portion of unit commitment, e.g., making sure there are adequate contingency reserves, but, I can't find where there is a requirement in the BAL standards for unit commitment to cover the peak load of the current day / next day plus contingency reserves plus frequency reserves plus regulation reserves. BAL-002 doesn't seem to cover all of this and seems to allow load shedding to cerate room for contingency reserves. So, we are suggesting a comment to develop a temporary requirement in TOP-002-3 until the new BAL standards, presently under development, include this (and I'm told that the present standard development effort does). GCS is proposing that this temporary requirement would be retired with the new BAL standard. GCS suggests that TOP-002-3 include a temporary requirement for BA's to validate unit commitment that meets the current day / next day projected peak loads plus reserve requirements until it is included in the BAL standards and at which time the requirement in the TOP standards could be retired. Operational Planning Analysis is ambiguous. R1 doesn't talk about the time frame of operations planning. The old version clearly had current day, next day and seasonal operations planning requirements that probably ought to be retained, as opposed to the ambiguous phrasing of R1. It also does not talk about what is being studied, e.g., the same contingencies included in the RC SOL methodology of FAC-011 for instance. GCS suggests defining the capitalized term of Operational Planning Analysis and add it to the NERC Glossary, especially since it is a capitalized term in the standard. R2 is confusing. We are sure the intent is that, if the Operational Planning Analysis results show that an SOL or IROL would be exceeded as a result of single / double contingencies covered by the RC's SOL Methodology of FAC-011, then the TOP must develop a plan to resolve the situation within the Tv of the SOL or IROL. GCS recommends that the SDT redraft R2 to make it less confusing and add clarity, maybe something like: "Each TOP shall develop plans to relieve an SOL or IROL violation identified in the results of Operational Planning Analyses within the time constraints related to the SOL or IROL (e.g., within the time frame of emergency ratings or the IROL Tv)" Such a change will also help clarify which entities are notified in R3. Currently, R3 is ambiguous as well since R2 as currently drafted seems to indicate that the Operational

Organization	Yes or No	Question 2 Comment
		Planning Analysis itself if the plan, and since everyone has a role in that plan, then R3 seems to indicate that everyone needs to be notified, which we doubt is the intent of the SDT.
Response: Regarding the removal of the Balancing Authority: The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2. The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis. The timeframe of the Operational Planning Analysis is part of the definition. No change made. The term "Operational Planning Analysis" is in the Glossary of Terms used in NERC Reliability Standards. No change made. TOP-001-2 has been revised to more clearly address the time relating to the exceedance of the subset of SOLs that is included in the limits that the Transmission Operator has informed the Reliability Coordinator to be important to the Transmission Operator's internal area. The SDT did not intend that everyone would have a role in the plan. The Transmission Operator would identify the entities that would have responsibility for the facilities that would be involved in the execution of the operating plan. Those are the only entities that must be notified, not all entities. No change made.		
Nebraska Public Power District	No	NPPD does agree in general with the intent of the proposals under this ballot, however there is change needed in TOP-002-3. The language in TOP-002-3 R2 is not clear and could be interpreted to require an entity to include all IROL's in the interconnection, which is way too broad. NPPD suggests that R2 of TOP-002-3 be reworded to be clear that the requirement is addressing IROL's and SOL's "within the Transmission Operator's Area".
Response: The Reliability Coordinator and the Transmission Operator must work in coordination and close communication. The Reliability Coordinator is expected to discuss with the Transmission Operator those areas and facilities within its area that are involved with, or can impact, IROLs and, possibly some of the SOLs that the Transmission Operator or other Transmission Operators have identified as affecting their internal area reliability. To be sure, there are IROLs and SOLs in the Bulk Electric System (BES) that any given registered entity may not be able to affect,		

Organization	Yes or No	Question 2 Comment
either positively or negatively. However, each IROL is the responsibility of a Transmission Operator. The Transmission Operator is obligated to notify those entities that have a role in its plan to resolve the IROL. No change made.		
SERC OC Standards Review Group LG&E and KU Energy PPL Supply	No	R1 - No comments R2 - The word "preclude" can be interpreted as "prevent", which would mean that any exceedance of an IROL or SOL would be a violation, regardless of duration. Other wording, such as "avoid" should be considered. R3 - No comments
Response: The SDT has revised the wording of Requirement R2 in response to comments. **R2.** Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Southern Company	No	R1 -It is still unclear to us if Operations Planning Analysis includes Contingency analysis as the NERC Glossary does not explicitly state. Edits to the rationale box were such that we could not understand the intent. R3-Is the standard expecting a comprehensive written plan as a result of the planning that takes place in R2? Is the intent of this requirement to notify all registered entities that may be affected by a mitigation plan for the next day?Example: An SOL is identified in the Operational Analysis for the next day from R2. The plan to mitigate this SOL is to call an IDC-TLR. The level of the TLR may or may not reach level 5. If the TLR reaches level 5 many generators will be required to be re-dispatched inside and outside of the TOPs area. This requirement will require the transmission operator to notify every Generator Operator that could possibly be re-dispatched for a TLR-5. It would be preferable to use the term "reliability entities" or at least replace the generic term "registered entities" with a listing of the Functional Model Entities that need to be notified. The use of registered entities would require reliability information to be given to marketing entities.
Response: The SDT has corrected an editing problem related to Requirement R1 and the text box. Requirement R2 doesn't mandate a written plan, but Measure M2 points to plans and processes. Typically plans in written form are easier to use to present evidence that a plan exists. Measure M2, therefore, recognizes written plan(s) as one option. Requirement R2 requires the Transmission Operator to plan. Without being so prescriptive as to tell "how" to do this, the SDT believes that the		

Organization	Yes or No	Question 2 Comment
Transmission Operator, in conducting its planning, will identify potential problem areas and what actions may be required to address those areas. The Transmission Operator must identify other entities which will have a role in executing any operating action plans that will be required to resolve issues as they arise. The SDT recognizes there are many different organizational structures and contractual arrangements in various areas of the BES. Each registered entity knows the arrangements that are in place for its facilities; for instance, generators are typically re-dispatched through Balancing Authorities and Generator Operators. It is not possible to specifically state each procedural action that must occur for this to take place. If the Transmission Operator typically calls the Balancing Authority, then the Balancing Authority knows how to implement the required actions. No change made. The SDT has added the word "NERC" to provide clarity to the requirement. **R3**. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).		
Wisconsin Electric Power Company	No	R3 the TOP should provide the plan to its RC and BA (s) in addition to notifying other entities of expected actions. The use of the phrase "all registered entities" is too open ended, and not limited to operational functions as it should be. In addition some actions may be required of entities not registered.
ITC	No	Regarding R3: Consistent with our comments on TOP-001 R6, we believe that the use of the word "registered" entities does not provide value, and only adds an unnecessary administrative step to operating personnel. We recommend just using "entities".
Response: The SDT has added the word "NERC" to provide clarity to the requirement. **R3**. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).		
City of Vero Beach	Ballot Comment	The City of Vero Beach still believes that unit commitment needs to be covered better when moving from the old TOP standards to the new TOP standards. Yes, unit commitment is a BA function, not a TOP function, and yes, BAL-002 does cover a portion of unit commitment, e.g., making sure there are adequate contingency reserves, but, I can't find where there is a requirement in the BAL standards for unit commitment to cover the peak load of the current day/next day plus contingency reserves plus frequency reserves plus regulation reserves. BAL-002 doesn't seem to cover all of this and seems to allow load shedding to cerate room for contingency reserves. So, we are suggesting a comment to develop a temporary requirement in TOP-002-3 until the new BAL standards, presently under development, include this (and I'm told that the present standard development effort does). The City of Vero Beach is proposing that this temporary requirement would be retired with the new BAL standard.

Organization	Yes or No	Question 2 Comment
Lakeland Electric	Ballot Comment	The new standard is just the TOP, which is appropriate; the old TOP-002-1 basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed(interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). BAs are eliminated from the new version 2 standard, and with no similar requirement in the BAL standards, FERC will likely see a reliability gap, no entity is ensuring that enough generation is being committed to serve current day / next day peak loads, e.g., no entity seems to be responsible for validating unit commitment.
Lakeland Electric	No	TOP-002-3: Operations Planning The prior version 2 standard was applicable to both the BA and the TOP. The new standard is just the TOP, which is appropriate; however, it was the old TOP-002-1 that basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed (at least that's how I interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). Since BAs are eliminated from the new version 2 standard, and since there is no similar requirement in the BAL standards that I am aware of, FERC will likely see a reliability gap that no entity is ensuring that enough generation is being committed to serve current day / next day peak loads, e.g., no entity seems to be responsible for validating unit commitment. The SDT claims that BAL-001-1 covers the operations planning perspective of a BA, but, BAL-001-1 covers unit commitment only loosely on an annual or monthly basis. The new version also doesn't talk about the time frame of operations planning. The old version clearly had current day, next day and seasonal operations planning requirements that probably ought to be retained, as opposed to the ambiguous phrasing of R1.

Response: Regarding the removal of the Balancing Authority from Requirements R5, R6, and R7:

The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority.

The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2.

The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2.

Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.

Organization	Yes or No	Question 2 Comment
Progress Energy	No	TOP-002-3 R2...Our initial concern was that an auditor could read this requirement as requiring a specific plan to address each IROL and SOL. This interpretation does not make much sense, but it is supported by the wording of the measure, which says, "Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL and each SOL." We can picture an auditor going down a complete list of IROLs and SOLs and asking, where is your plan for A, where is your plan for B, etc.The standard should not require the Transmission Operator to prepare a plan to address IROLs and SOLs unless the Operational Planning Analysis indicates the potential for a thermal or voltage problem for that element due to normal (N-0), contingency (N-1), or sensitivity analysis result. So, the logical way to read this requirement is to say that the completion of the Operational Planning Analysis is the "plan", and if there are no IROL/SOL limits exceeded, then you have met the requirement. If this is what the SDT meant, then the wording of the requirement should be revised and clarified. Also, We are concerned about the requirement to "...plan to preclude operating in excess...", because "preclude" is defined to mean "make impossible" or "take action in advance to make impossible". Precluding these events is inconsistent with the time limits established in the new TOP-001-3 standard. This could be read to require pre-contingency action for any contingency involving an IROL/SOL, which could cause major operational problems to say the least. All of the prior standards, including the TOP, TPL, and the Rules of Procedure governing the seasonal assessment process provide latitude in how studies are performed, and what pre- and post- contingency actions are taken. This standard should be clarified to provide comparable latitude in addressing IROL and SOL issues. Just changing "preclude" to "mitigate" would be a good start.... Also, requirement R2 is unacceptably vague in that it requires plans for SOLs that "support internal area reliability" without indicating how those SOLs are identified or selected as a subset of all SOLs. Also, R8 of TOP-001-3 requires that the RC be notified of the existence of these SOLs, whatever they are....

Response: The SDT believes that Operational Planning Analysis (OPA) will identify areas that need specific attention and specific plans. A Transmission Operator may have a standing practice of constraint management which will address the great majority of IROL or SOL requirements. In such a case, evidence of the existence of such a practice and evidence that the practice was followed will address the requirement. For those issues identified in the OPA as needing specific operating action plans, the Transmission Operator can show how each is covered in its procedures or, when required, in case-specific plans. Such plans may be standing or temporary, depending upon the system conditions involved. The standards are not prescriptive as to "how" the entity is to address the issues, just what the entity is required to do. No change made.

The SDT has revised the wording of Requirement R2.

Organization	Yes or No	Question 2 Comment
R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. The SDT changed "local area" to "internal area" based upon comments received from the industry. While all SOLs are relevant for only localized issues, not widespread BES issues, each Transmission Operator has a Transmission Operator area within which it has primary reliability responsibilities. The SDT reminds you that the methodology for developing SOLs, as required by the FAC standards, requires that all SOLs respect the Facility Ratings used in the development of the SOLs. No change made.		
Colorado Springs Utilities	Yes	Colorado Springs Utilities respects the difficulty in crafting language which satisfies all potential interpretations of a requirement. We do, however, suggest changing "planning to preclude operating" under R2 to "plan to operate", giving you the following: "Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator via the Operational Planning Analysis performed in Requirement R1 as supporting its internal area reliability."Perhaps the definition of SOL should be revised to include the principle of "internal area reliability". Then, everything not IROL or SOL could go back to being facility ratings or the like.
Response: The SDT has revised the wording of Requirement R2. **R2.** Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. The SDT changed "local area" to "internal area" based upon comments received from the industry. While all SOLs are relevant for only localized issues, not widespread BES issues, each Transmission Operator has a Transmission Operator area within which it has primary reliability responsibilities. The SDT reminds you that the methodology for developing SOLs, as required by the FAC standards, requires that all SOLs respect the Facility Ratings used in the development of the SOLs. No change made.		
Yes		
Yes		
Yes		

Organization	Yes or No	Question 2 Comment
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Organization	Yes or No	Question 2 Comment
Yes		
Yes		
Yes		
Response: Thank you for your support.		

3. **The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The majority of the comments were asking for clarification. The SDT made specific changes to Requirements R2 & R3 to spell out that the intent of the SDT is to allow the Transmission Operator and Balancing Authority to request any data they need to perform their monitoring and operations planning functions as long as the entity has a reliability-based need for that data. The SDT also deleted the two sub-bullets in Requirement R1 in this same vein.

R2. Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements.

R3. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements .

Organization	Yes or No	Question 3 Comment
City of Tacoma or Tacoma Public Utilities	No	1. In general, the standard language as written is vague. 2. R1: Though a minimum list of required data may be construed as too prescriptive and may "stifle creativity and innovations," the absence of a pre-defined list will promote inconsistencies between entities and may risk an Auditor interpreting what data is needed for an "Operational Planning Analysis" differently from the utility. 3. R1.1: The term "long term outages" needs a definition. How long is "long term?" 4. R1.1: The term "operating parameters" also need a definition.

Response:

1. Without a specific comment, the SDT is unable to respond. No change made.
2. The noted audit concern can never be eliminated based on the reality that auditors may incorrectly cite an audited entity for actions or items not required by the standard. Requirement R1 is actually quite specific – the data specification limits the data to be provided as only that data explicitly requested by a Transmission Operator or a Balancing Authority. If the data is not on the list, than the data need not be supplied regardless of what an auditor considers as necessary. A given auditor may find the entity non-compliant but that non-compliance should be

Organization	Yes or No	Question 3 Comment
overruled based on the requirement as written. No change made. **3.** (and 4.) The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
MRO's NERC Standards Review Forum	No	As currently written, R1.1 could be interpreted to include all of the distribution facilities of a Registered Entity. It needs to be revised to include only the lower voltage facilities proven to impact the reliability of the BES. In R1.1, please clarify “long-term” as the term applies to outage of BES Facilities. What length of time must pass before an outage I is considered “long-term”? In R1.1, clarify “Operating Parameters” as the term applies to BES Facilities and those Facilities at voltages lower than the BES. We recommend that a list of required parameters be included within the Requirement. Recommend rewording R2 (and R3) as follows: “Each Transmission Operator shall distribute its data specification document to all NERC Registered Entities that provide Facility status to the Transmission Operator.”
Response: The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted. The technical issue raised by the commenter will not be resolved by the proposed rewording. The proposed rewording is to have the requesting entity send documentation to those that already provide data. The proposed rewording begs the question of what to do with new entities, or entities that have changed Transmission Operators. However, the SDT has made clarifying changes to the wording of both requirements. **R2**. Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator’s reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority’s reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements . As newly worded, this requirement limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis.		
Cowlitz County PUD	No	Cowlitz has no disagreement with any of the changes made; however Cowlitz struggles why the Load-Serving Entities (LSEs) are included in the Applicability section. From requirements R2 and R3 it is clear that Facility monitoring and status is involved. From the Reliability

Organization	Yes or No	Question 3 Comment
		Functional Model it is clear that LSEs do not own Facilities, but rather are more ambassadors between the End-use Customers and registered entities that do own facilities. Although the Statement of Compliance Registry Criteria implies that the LSEs might own UVLS and/or UFLS equipment, the Reliability Functional Model is clear that the LSE only helps identify those critical customer loads that should be excluded in such load shedding programs. Therefore, Cowlitz urges the SDT to remove the LSEs from the Applicability section. Cowlitz also suggests that Distribution Providers be included in the Applicability section as these entities do own Facilities that may require monitoring and status by the TOP and BA.
Response: Load-Serving Entity's have load data that is necessary to conduct an Operational Analysis. While a Load-Serving Entity may be by default required to provide such information, that does not mean that every Load-Serving Entity will be asked to provide such information (as some reliability entities provide their own composite forecast loads and do not need each Load-Serving Entity's forecast.) No change made. There are no other comments that there is any data needed by the Transmission Operator or Balancing Authority that must be supplied by the Distribution Provider. No change made.		
Illinois Municipal Electric Agency	Ballot Comment	Illinois Municipal Electric Agency (IMEA) appreciates the SDT's efforts on this initiative to simplify and improve this set of Reliability Standards. We are supportive of those Requirements which apply to the DP, LSE, and TO functions; however, IMEA is voting Negative to support concerns which have been expressed to remove the following language from TOP-003-2, R1.1: "and Facilities at voltage levels lower than the BES."
FirstEnergy	No	R1 - Subpart 1.1, Bullet #2 - We suggest that the team strike the phrase "and Facilities at voltage levels lower than the BES". NERC reliability standards are meant to provide an adequate level of reliability to the Bulk Electric System, and therefore non-BES requirements are beyond the scope of the standards. Furthermore, the current NERC initiative to revise the definition of BES and provide specifics around what is both included and excluded will alleviate any potential gaps in reliability of the BES.
Georgia Transmission Corporation	No	Section 215 of the FPA provides that the ERO "shall have authority to develop and enforce compliance with reliability standards for only the BPS."In Order 743A, the commission acknowledged that "Congress has specifically exempted 'facilities used in the local distribution of electric energy" from the BPS definition.R1.1 for TOP-003-2 references distribution assets which are outside the scope of NERC standards. GTC recommends removing reference to "Facilities at voltage levels lower than the BES"
Commonwealth of Massachusetts Department of	Ballot Comment	The other issue is in TOP-003-2 R1.1 which states: R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to

Organization	Yes or No	Question 3 Comment
Public Utilities		perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: o Long term outages of Bulk Electric System (BES) Facilities. o Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES. Some RSC members believe using language such as "but not limited to" and "levels lower than the BES" to be problematic and beyond the scope of what is needed and also creates potential for compliance issues.
ISO/RTO Standards Review Committee	No	The second bullet under R1, 1.1 facilities "at voltage levels lower than the BES;" we believe that these facilities are not enforceable under the NERC Standards. We believe any such references should be removed. We suggest removing this phrase from the bullet.
ISO New England Inc.	No	The second bullet under R1, 1.1 facilities "at voltage levels lower than the BES;" we believe that these facilities are not enforceable under the NERC Standards. We believe any such references should be removed. We suggest removing this phrase from the bullet.
Northeast Power Coordinating Council, Inc.	Ballot Comment	TOP-003-2 R1.1 states: R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: o Long term outages of Bulk Electric System (BES) Facilities. o Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES NPCC believes language such as "but not limited to" and "levels lower than the BES" to be problematic and beyond the scope of what is needed in the standard and also creates potential for compliance issues.
Pepco Holdings Inc	No	In R1.1 has an open ended requirement for operating parameters for non BES facilities. Should the language limit that to only those facilities that have an impact on BES facilities? If so, should long term outages of those facilities also be required?
PSEG Energy Resources & Trade LLC PSEG Fossil LLC Public Service Electric and Gas Co.	Ballot Comment	In TOP-003-2 Operational Reliability Data, the PSEG companies do not understand the need for the sub-BES voltage data reporting requirement in the second bullet of R1.1. This open-ended requirement appears to be potentially extremely burdensome to LSEs and TOs with no justified basis of its need to maintain BES reliability. If the sub-BES voltage phrase is removed from the Requirement so that it to simply states "Operating parameters for BES Facilities" The PSEG companies expect that they would change their vote to affirmative. Additionally, in TOP-003-2 R1.1, the phase "Long term outages" is interpreted to be planned

Organization	Yes or No	Question 3 Comment
		season outages not emergent issues that result in a long duration outage of a BES facility. Please clarify if this is a correct interpretation of the intent of the SDT.
Duke Energy Carolina	Ballot Comment	3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 No Comments: The second bullet under R1.1 has been changed so that now operating parameters for all facilities at voltages lower that BES are required. The phrase “at the discretion of the Transmission Operator or Balancing Authority” must be restored in this requirement. 3. TOP-003-2 Requirement 1, Part 1.1: This provides for exchange of data required to perform Operational Planning Analyses and real-time monitoring. These data include “Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES [emphasis added].” We believe the latter clause is unenforceable under the NERC standards and should therefore be removed.
Northeast Power Coordinating Council Hydro One Networks Inc. Independent Electricity System Operator	No	Referring to the second bullet under R1, Part 1.1, “...Facilities at voltage levels lower than the BES;” these facilities are not enforceable under the NERC Standards. Any such references should be removed. Editorial comment: remove M5 because there is no corresponding R5.
SERC OC Standards Review Group LG&E and KU Energy PPL Supply	Yes	R1.1 - It is our understanding that bullets should be avoided in the requirements. R2 - No comments R3 - No comments R4 - No comments
BC Hydro	No	R1.1 refers to “Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES”. In the previous Consideration of Comments, it was noted that “Facilities below 100kV may have material impact to the BES and, as such, are within the scope of the requirement ...”. BC Hydro feels that the wording in R1.1 “Facilities at voltage levels lower than the BES” is open-ended and it does not clearly reflect that these extra Facilities have been deemed as having material impact to the BES and therefore are subject to the NERC

Organization	Yes or No	Question 3 Comment
		MRS.
Roger C Zaklukiewicz	Ballot Comment	Requirement R1 needs to be modified as the following terms in 1.1 are problematic to compliance and enforcement. Remove the term "but not limited to". Why must the data to be exchanged include that on all facilities that operate at levels lower than the Bulk Electric System to ensure the reliability of the interconnected BES - especially if the BES is to be recognized as the "bright line" transmission system that operates at 100 kV or above.
Public Service Enterprise Group LLC	No	The PSEG Companies interprets “long term outages” to be planned season outages not emergent issues that result in a long duration outage of a BES facility.
United Illuminating Co.	Ballot Comment	UI Votes negative due to TOP-003 R1.1 requirement that the TOP can request operating parameters for Facilities at voltage levels lower than the BES. If a facility lower than 100 kV is required to be included in the BES then the exception process should be followed to include it in the BES. Non-BES designated facilities cannot be subject to mandatory reliability standards.
Puget Sound Energy	Yes	The second bullet in R1.1 needs clarification. As originally drafted, this was permissive language allowing entities to include non-BES information in their data specifications. However, with the revisions, this section now requires all entities to do so, whether or not such data is necessary or pertinent for their operations. As a result, the second bullet should be revised to retain its permissive character or should be removed from the standard altogether.
Response: The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
Ameren	No	In R1, 1.1 “at the discretion of the Transmission Operator or Balancing Authority” phrase should be reinstated.
Response: The SDT has made changes to requirements R2 & R3 to address this issue. As newly worded, this limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis. **R2.** Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator’s		

Organization	Yes or No	Question 3 Comment
reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements .		
Electric Market Policy	No	Is this question meant to refer to TOP-003-2? If so, then Dominion's response is that we agree, but do not see why the SDT felt it necessary to add "web postings with acknowledgement" to M2 and M3. The sentence "Such evidence could include but is not limited to ....” was sufficient without the addition. Dominion believes this language will invite others to want to add the types of evidence found usefher may grow over time.
Response: The measurement language was linked to the closed-loop nature of some forms of evidence as opposed to other forms. When request and response is directly and independently documented there is no problem. However, the use of posting is indirect. In essence there is another step needed, i.e., to tell the other person the request is posted. Without that step an entity could be held non-compliant for something it never received a request for. The measurement merely requires that for a Transmission Operator to use that form, there is an added need to "prove" the other party knows the requests exists. No change made.		
ITC	No	ITC is concerned with the removal from R1.1 of the phrase "...at the discretion of the Transmission Operator or Balancing Authority". Why was this removed? The TO and BA should have discretion of what data it needs (especially at the sub-BES level) to perform Operational Planning Analysis and Real time monitoring. Also in R1.1, please define what "long-term outages" are.
Duke Energy	No	The second bullet under R1.1 has been changed so that now operating parameters for all facilities at voltages lower that BES are required. The phrase "at the discretion of the Transmission Operator or Balancing Authority" must be restored in this requirement.
Response: The SDT made clarifying changes to Requirements R2 & R3 to address this issue. As newly worded, this requirement limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis. **R2**. Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability		

Organization	Yes or No	Question 3 Comment
monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements . The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
PJM Interconnection, L.L.C.	Ballot Comment	PJM questions the 30 minute limitation placed on SOLs that are identified by TOPs for use by the RCs (TOP-001 R9). In addition PJM does not agree with the inclusion of non-BES assets (TOP-003 R1).
Response: (see Q1 for response to 30 min question) The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
Florida Municipal Power Agency	No	R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards. It would also be beneficial to split this requirement into two requirements, one for real-time and one for Operational Planning Analysis since they are separate databases. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: (i) Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ...."; hence, the second use of Facilities in the phrase ought to be deleted, or at minimum, replaced with the term Elements; and (ii) although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 "mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. FMPA suggests clarifying who is mutually agreeing. Also, from a reliability perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14.R1.3 and R1.4 - should have the same characterization of R1.2,

Organization	Yes or No	Question 3 Comment
		e.g., "mutually" or stakeholder process driven to establish a schedule.
Response: In writing requirements such as these, there is a need to balance the need to recognize the many differences among entities verses the desire for explicit mandated behavior. To provide a list that meets one entity's data requirements will inevitably be too much or too little for another entity. Over the postings of this standard the Industry comments favored the flexibility approach. No change made. The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted. Mutually agreeable format is between the requesting entity and the entity being requested. There is no implied right given to a Transmission Operator or Balancing Authority to purchase tools that cannot be supported by the assets it coordinates. If there is a new technology that none of its members can support, must the members all be required to install new equipment for that change? The current sub-requirement has not been questioned by any other entity. No change made.		
City of Green Cove Springs	Ballot Comment	R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards. It would also be beneficial to split this requirement into two requirements, one for real-time and one for Operational Planning Analysis since they are separate databases. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: (i) Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ...."; hence, the second use of Facilities in the phrase ought to be deleted, or at minimum, replaced with the term Elements; and (ii) although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 "mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. GCS suggests clarifying who is mutually agreeing. Also, from a reliability related perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14. R1.3 and R1.4 - should have the same characterization of R1.2, e.g., "mutually" or stakeholder process driven to establish a

Organization	Yes or No	Question 3 Comment
		schedule. GCS believes significant changes to the standards are required; hence, it is too early to opine on the VSLs.
Response: In writing requirements such as these, there is a need to balance the need to recognize the many differences among entities verses the desire for explicit mandated behavior. To provide a list that meets one entity's data requirements will inevitable be too much or too little for another entity. Over the postings of this standard the Industry comments seem to favor the flexibility approach. No change made. The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted. Mutually agreeable format is between the requesting entity and the entity being requested. Requirement R1 must be viewed in the context that there "may be" more than one data specification used by a Transmission Operator or Balancing Authority. Requirement R1 allows the flexibility to customize specifications for each entity that is being asked to provide data for the operating analysis tools in question. No change made.		
Wisconsin Electric Power Company	No	R2 & R3 should not use the term monitored, the TOP or BA should distribute its data specification to all entities that are included in that specification to enable the proper Operational Planning Analyses and Real-time monitoring. R4 should not include both asset owners and operators, example generator xyz net output at the transmission interface needs to be the responsibility of one and only one entity to provide. Very confusing if both the GO and GOP have the same responsibility.
Response: The commenters provide no alternative to the term "monitored". Given the limited number of comments regarding this term, no change is made to the requirement. The SDT sees no problem with listing asset operators and owners in this requirement. Each entity will have received a different and specific data specification from the Transmission Operator or Balancing Authority so there should be no problem. No change made.		
Imperial Irrigation District	Yes	Suggestions/Comments: Could R2 & R3 be included as sub bullets of R1 (R1.1 & R1.2)? R1 - Each Transmission Operator and Balancing Authority shall have create and maintain a formal documented plan/procedure for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. R2 - Each Transmission Operator shall distribute its formal data plan/procedure specification to the Reliability Coordinator and entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator.

Organization	Yes or No	Question 3 Comment
		R3 - Each Balancing Authority shall distribute its formal data plan/procedure specification to the Reliability Coordinator and to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.
Response: The SDT believes that including Requirements R2 & R3 as sub-bullets would make Requirement R1 unmanageable and extremely difficult to measure. No change made. The SDT believes the suggested language does not provide any additional clarity. No change made. R2 & R3 - No justification for including the Reliability Coordinator was provided and the SDT sees no reliability reason to include the Reliability Coordinator in this process. No change made.		
Arizona Public Service Company	No	The need for the proposed “overarching” document is not necessary and appears cumbersome for many regions of the country such as the western interconnect.
Response: There is no mandate for an “overarching” document. The requirement is to provide document for any data that is needed for reliability. No change made.		
U.S. Bureau of Reclamation	Ballot Comment	The term "required" in requirement R1 "Each Transmission Operator and Balancing Authority shall have create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring." is not defined and does not encourage coordination amond the entities. It is suggested that coordination would be encouragedif an impartial entity provided oversight. The following language would resolve the undefined term and encourage coordination. "Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring as required by the requirements in the NERC Reliability Standards. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: o Long term outages of Bulk Electric System (BES) Facilities. o Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES. 1.2. A mutually agreeable format. 1.3. A periodicity for providing data. 1.4. The deadline by which the respondent is to provide the indicated data. 1.5. The specific NERC Reliability Standard requirement for which the data is needed. R5. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification will notify the Reliability Assurer if the data specifications are not consistent with

Organization	Yes or No	Question 3 Comment
		the NERC Reliability Standard Requirements. R6. The Reliability Assurer will review the data specifications for consistency with the NERC Reliability Standards and notify the Transmission Operator and Balancing Authority of the results and changes if any that are needed."
Response: The word "required" is used specifically in its traditional meaning relating to something that is critical and at the same time something that is missing. The wording of the requirement precludes the obligation of having documentation for data that an entity already has. Thus if a Transmission Operator has all the data it needs to do its reliability monitoring and its real time analysis, then no documentation specification is needed. However, when data is required, than a formal specification is mandated so that the entity receiving the request "knows" what is being requested. As written an auditor cannot arbitrarily ask for documentation of a specific piece of data that has been in use by a Transmission Operator and hold that Transmission Operator non-compliant for not having the specification. The fact that the data is in use serves as proof the data has been correctly obtained and received. No change made. Expanding a requirement to include procedural items does more to limit the flexibility and utilization of new technologies than it does to improve data exchange of current technologies. The two bulleted items under R1.1 of TOP-003-1 will be removed in the next posting. There are no data requirements in the current standards that cover the items in each and every analysis tool. Moreover, the current Reliability Standards Development process requires that all mandates be in the standard requirements themselves and not left as a fill-in-the-blank measure as defined by the subjectivity of a Reliability Assurer. No change made.		
NorthWestern Energy	Ballot Comment	TOP-003-2 We disagree with the new proposed version of the standard; the requirements obligate the Transmission Operator and Balancing Authority to create documented specifications for the data necessary to perform required Operational Planning Analysis and Real-time monitoring. This data is already spelled out and identified in the current version of TOP-003-1. The data requirements in the current standard TOP-003-1 have been tested and have been proven to be effective in gathering necessary data required by TOPs and BAs. The new proposed TOP-003-2 places a greater burden and responsibility on TOPs and BAs. If something is missed in the newly created specification for data necessary to perform Operational Planning Analysis, the responsibility falls on the TOP or BA alone.
Response: The word "required" is used specifically in its traditional meaning relating to something that is critical and at the same time something that is missing. No change made. If something is missed in the specification, the SDT believes that the onus should be on the Transmission Operator or Balancing Authority. The data requirements are thus defined by the Transmission Operator and not by an auditor. As written an auditor cannot arbitrarily ask for documentation of a specific piece of data that has been in use by a Transmission Operator and hold that Transmission Operator non-compliant for		

Organization	Yes or No	Question 3 Comment
not having the specification. The fact that the data is in use serves as proof the data has been correctly obtained and received. No change made.		
Lakeland Electric Beaches Energy Services	No	TOP-003-3: R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced, and will probably be perceived by FERC as being too flexible a requirement that would allow a TOP or BA to do less than they are currently required. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards to at least prove to FERC that we are not subtracting data/information requirements. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: 1. Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ....” The second use of Facilities in the phrase ought to be deleted (see below), or at minimum, replaced with the term Elements. 2. Although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 “mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. Suggest clarifying who is mutually agreeing. Also, from reliability related perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14. R1.3 and R1.4 - should have the same characterization of R1.2, e.g., "mutually" or stakeholder process driven to establish a schedule.
Response: In writing requirements such as these, there is a need to balance the need to recognize the many differences among entities verses the desire for explicit mandated behavior. To provide a list that meets one entity’s data requirements will inevitable be too much or too little for another entity. Over the postings of this standard the Industry comments seem to favor the flexibility approach. No change made. The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		

Organization	Yes or No	Question 3 Comment
Mutually agreeable format is between the requesting entity and the entity being requested. As has been cited in previous posting comment responses, the SDT believes that the entities involved will be reasonable in approaching a solution to a problem. However, if a resolution can't be reached, the disputing entities can always fall back on existing dispute resolution procedures administered by their Reliability Coordinator. No change made. This standard requires that data be requested when needed and that all parties come to a reasonable solution. If a resolution can't be reached, the disputing entities can always fall back on existing dispute resolution procedures administered by their Reliability Coordinator. No change made.		
Progress Energy	No	We perform many studies in different time frames that could be viewed as an "Operational Planning Analysis", from seasonal assessments, to OPC studies, to outage planning studies, day-ahead planning studies, real-time CA studies, etc. Our question is, which of these studies will be subject to all of the requirements in TOP1, 2, 3, and particularly to the data specification requirements in TOP-003? Will Transmission Operators be expected to meet these requirements for ALL studies, or can we designate one specific study process as the "Operational Planning Analysis" study (and, by implication, exempt others from the requirements). Also, TOP-003, R1 also includes "real-time monitoring" in the scope of the requirement for the data specification, so does this include the EMS and all of its data? This would require multiple data specifications, because the EMS and off-line PSS/E models we use to perform various studies would require different data specifications, have different contacts that provide information, etc.
Response: The commenter's first question is concerned about an auditor making the decision about what data must be specified. The word "required" is used in Requirement R1 specifically in its traditional meaning relating to something that is critical and at the same time something that is missing. The wording of the requirement precludes the obligation of having documentation for data that an entity already has. Thus if a Transmission Operator has all the data it needs to do its reliability monitoring and its Real-time analysis then no documentation specification is needed. However, when data is required for "any" of its analysis programs, then a formal specification is mandated so that the entity receiving the request "knows" what is being requested. It is up to the Transmission Operator or Balancing Authority to determine what data it needs to perform its studies. In other words, you select what data you need to perform your duties. There is no mandate for data specifications for data that a Transmission Operator already has. The standard does not specify which tools are considered as monitoring tools. If the EMS is defined as your monitoring tool then whenever additional data is needed, this standard requires the Transmission Operator to formally ask an entity for that data in the form and the time frame needed. The concern that a Transmission Operator will be found non-compliant because there is no one single document that covers all data is a misplaced concern. This requirement is written to be forward looking, not looking backward.		
City of Tallahassee	Ballot Comment	While it specifies that the examples are only possibilities for evidence, the inclusion of "with acknowledgement" to "web postings" in M2 & M3 for TOP-003-2 will become onerous. It

Organization	Yes or No	Question 3 Comment
		requires another entity to respond in order to have evidence we were compliant.
Response: The measurement language was linked to the closed-loop nature of some forms of evidence as opposed to other forms. When request and response is directly and independently documented there is no problem. However, the use of posting is indirect. In essence there is another step needed, i.e., to tell the other person the request is posted. Without that step an entity could be held non-compliant for something it never received a request for. The measurement merely requires that for a Transmission Operator to use that form, there is an added need to "prove" the other party knows the requests exists. No change made.		
Luminant Energy	No	While we agree with the concept of the TOP and BA creating a specification for data necessary for Operational Planning and Real-time monitoring, we feel that Requirement 1.2 should explicitly state that the format should be mutually agreeable to the TOP and BA and the parties receiving the data request under R2 and R3. Additionally, for R1.3, we feel the same mutually agreeable requirement between the TOP and BA and the parties receiving the data request should be added for the periodicity requirement.
Response: Mutually agreeable format is between the requesting entity and the entity being requested. The SDT believes this is clear with the existing wording. This applies to the periodicity element as well. No change made.		
American Electric Power	Yes	Additional clarity is needed as to the type(s) of data that would be considered necessary for performing operational planning analysis and real time monitoring. For example, will the requirements as specified in attachment 1 for TOP-005-2 be incorporated into TOP-003-1?
Response: Requirement R1 is actually quite specific – the data specification will include any and all data needed by a Transmission Operator or a Balancing Authority to fulfill their responsibilities. If the data is not on the list, then the data need not be supplied. However, the SDT has made clarifying changes to Requirements R2 & R3 that address this issue. As newly worded, this requirement limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis. **R2.** Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements .		
Northeast Utilities	Yes	Editorial comment: Remove "M5" because there is not any corresponding text and there is not a corresponding R5.

Organization	Yes or No	Question 3 Comment
Response: Agreed.		
Colorado Springs Utilities	Yes	Colorado Springs Utilities believes the question should be directed toward TOP-003-2.
Bonneville Power Administration	Yes	
Western Electricity Coordinating Council	Yes	
Southern Company	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Indeck Energy Services	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your support.		

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. Do you support the proposed VRF. VSL and Time Horizon assignments? If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The SDT made some changes to the VRFs, VSLs, and Time Horizons based on feedback received. Because these are compliance elements, they are not viewed as substantial changes to the standards.

One commenter requested a time frame for failing to inform per TOP-001-2, Requirement R2. The SDT made no change because each situation is different, preventing a universal time frame to inform.

The VSLs for TOP-001-2, Requirements R3, R5, and R6, TOP-002-3, Requirement R3, and TOP-003-2, Requirements R2 and R3, were modified to remove percentages. Some commenters found them confusing with both integer and percentage values. The sample sets are expected to be small enough that percentages will not work well.

The VSLs for TOP-001-2, Requirement R6 were further clarified to eliminate confusing language.

Several commenters expressed that VRFs, VSLs, and Time Horizons were not ready to be balloted until the requested changes to other parts of the standard were made. With the need to employ a successive ballot, this becomes a moot point.

Some commenters expressed that the High VRF associated with requirements to operate within the subset of non-IROL SOLs required to be identified per TOP-001-2, Requirement R8 should be changed to a Medium VRF. The SDT felt because these SOLs are viewed as being so important that a Transmission Operator must inform the Reliability Coordinator of them that the associated requirements warrant a High VRF as these SOLs are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined T_v, but must respect the Facility Rating or Stability criteria upon which they are based.

The Moderate and High VSLs for TOP-001-2, Requirement R8 were modified by changing the “or” between the ranges to an “and”. “Local” was replaced with “internal” for all of the VSLs to be consistent with the requirement.

Operations Planning and Same-day Operations were added to the TOP-001-2, Requirement R8 time horizon.

The VRF for TOP-002-3, Requirement R3 was changed to Medium.

For consistency, the VSL for TOP-001-2, Requirement R2 has been modified to match the language of the requirement more closely.

TOP-003-2, Requirement R1 VSLs were modified to include additional gradations for missing three and four or more parts of the requirement.

Several commenters were concerned about escalation of the VSLs associated with TOP-003-2, Requirement R4 for missing a few pieces of data. One even suggested the data should be prioritized based on unit size. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc., and no change was made. One commenter was concerned that VSLs for TOP-001-2, Requirement R6 do not consider small entities and suggested prioritizing of the VSLs based on unit size. The SDT believes VSLs do consider the impact on small entities. The SDT did not make any changes to prioritize the VSLs based on unit size because that is only applicable for adequacy and unit size is not relevant for transmission security.

One commenter requested the TOP-001-2, Requirement R1 Severe VSL should use an “or” condition rather than the “and” condition for failing to follow a directive and informing of the reason for not following the directive. The SDT felt the “and” condition was appropriate.

One commenter suggested that TOP-001-2, Requirement R6 was fundamentally modified to include data when telemetering equipment was changed to telemetry. The SDT agreed and modified the requirement accordingly.

TOP-001-2, R8: Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

TOP-002-3, R3: Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor:Medium] [Time Horizon: Operations Planning]*

TOP-001-2, R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that

				Transmission Operator.

TOP-001-2, R3	The Transmission Operator did not inform one other Transmission Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators that are known or expected to be by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	1. The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. 2. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.

TOP-001-2, R5	The Transmission Operator did not inform one other Transmission Operator of its operations known or expected to result in an Adverse Reliability Impact on that respective Transmission Operator Area when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform four or more other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.

TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	3. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 4. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

TOP-001-2, R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability.	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability.

		area reliability.	area reliability.	
TOP-002-3, R3	The Transmission Operator did not notify one registered entity, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more registered entities identified in the plan(s) as to their role in the plan(s).
TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	5. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 6. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.

Organization	Yes or No	Question 4 Comment
City of Tacoma or Tacoma Public Utilities	No	1. TOP-001-2: In general, when “failure to inform” results in VSL, the timeframe for informing needs to be defined. 2. TOP-002-3, R3: The VSL language for all levels is confusing. At the minimum, the percentages for should be consistent between Lower, Moderate, High and Severe. 3. TOP-003-2: Similar to TOP-002-3, the VSL language for all levels is confusing and should be consistent between VSL levels.

Response: 1) The SDT disagrees with establishing a uniform time frame for response as each situation will be different. No change made.

2) and 3) The SDT concurs and has clarified the language.

TOP-002-3, R3	The Transmission Operator did not notify one registered entity, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more registered entities identified in the plan(s) as to their role in the plan(s).

Organization	Yes or No	Question 4 Comment
Duke Energy Carolina	Ballot Comment	4. The VRF, VSL, and Time Horizons are part of a non-binding poll. Do you support the proposed VRF. VSL and Time Horizon assignments? If you do not support these assignments or you agree in general but feel that

Organization	Yes or No	Question 4 Comment
		alternative language would be more appropriate, please provide specific suggestions in your comments. 1 No Comments: Consistent with our comments about the unacceptable phrase “supporting local area reliability” we do not support the VRFs and VSLs. 5.
Duke Energy	No	Consistent with our comments about the unacceptable phrase “supporting local area reliability” we do not support the VRFs and VSLs.
Response: Please see the SDT response to the “supporting local area reliability” issue in the associated comments for Q1.		
Ameren	No	As stated in comments above, we have concerns about the newly introduced term “internal” area reliability in TOP-001 and TOP-002 and proposed Medium VRF to the corresponding requirements.
Response: Please see our comments regarding the “internal” area reliability issue in the responses to Q1. The SDT believes the Medium VRF is appropriate as the SOLs that are identified by the Transmission Operator are important SOLs. No change made.		
Florida Municipal Power Agency	No	FMPA has no comments on the VRFs FMPA believes significant changes to the standards are

Organization	Yes or No	Question 4 Comment
		required; hence, it is too early to opine on the VSLs.
FirstEnergy	No	We cannot support the current VSL until our suggested changes to the requirements are made.
Response: Thank you for your response.		
Northeast Utilities	Yes	For TOP-001-2 Requirements R3, R5, R6 and R8, suggest changing "or' to "and" - that is change "...more than x% OR less than or equal to y%..." to "...more than x% AND less than or equal to y%..."
Northeast Power Coordinating Council Independent Electricity System Operator Hydro One Networks Inc	No	Referring to the Moderate and High VLSs for TOP-001-2 Requirements R3, R5, R6 and R8, where these VLSs state "...more than x% or less than or equal to y%...", suggest changing to ""...more than x% and less than or equal to y%...". These changes would also make these VLSs consistent with the language of TOP-002-3 and TOP-003-2.
Response: For Requirements R3, R5, and R6, the SDT decided to eliminate percentages in favor of integer VSL levels given the sample set sizes will likely be small even for a large Transmission Operator.		

TOP-001-2, R3	The Transmission Operator did not inform one other Transmission	The Transmission Operator did not inform two other Transmission	The Transmission Operator did not inform three other Transmission	7. The Transmission Operator did not inform its Reliability Coordinator of

Organization			Yes or No	Question 4 Comment
	Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	Operators that are known or expected to be by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. 8. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
TOP-001-2, R5	The Transmission Operator did not inform one other Transmission Operator of its operations known or expected to result in an Adverse Reliability Impact on that respective Transmission Operator Area when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform four or more other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment,	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of	9. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and

Organization			Yes or No	Question 4 Comment
	control equipment, and associated communication channels between the affected entities.	equipment,control equipment ,and associated communication channels between the affected entities.	telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	associated communication channels. 10. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
For Requirement R8, the recommended change was made and the percentage VSLs were retained as there is more uncertainty over the sample set sizes for this requirement.				
Puget Sound Energy			No	In TOP-001-2, R8, the time horizon should include Operations Planning and Same-day Operations, in addition to the currently-listed Real-Time Operations. In TOP-002-3, R3, the VRF is listed as “High”. However, according to the document “Violation Risk Factor and Violation Severity Level Assignments”, the appropriate level is “Medium”, which is also more consistent with the assignments associated with other requirements throughout these proposed standards. In TOP-002-3, the VSL matrix

Organization	Yes or No	Question 4 Comment
		entries associated with R3 need to have additional references to "reliability entities" changed to "registered entities".
Response: The SDT has made the suggested changes to TOP-001-2, Requirement R8 and TOP-002-3, Requirement R3. **TOP-001-2, R8**: Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]* **TOP-002-3, R3**: Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor:Medium] [Time Horizon: Operations Planning]* For the TOP-002-3, Requirement R3 VSL, no change was made because the VSLs already used the term registered entities as requested.		
ReliabilityFirst	No	ReliabilityFirst generally agrees with the Violation Risk Factors (VRFs) but disagrees with the Violation Severity Levels (VSLs) for the following reasons:TOP-001-2 VSLs1. VSL for R2a. The word "comply" is not within the language of R2 and should be removed from the VSL. R2 simply requires the Applicable Entities to "... inform its Transmission Operator...". This is a violation of the FERC Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement" 2. VSL for R8a. The term "local area reliability" should

Organization	Yes or No	Question 4 Comment
		be replaced with “internal area reliability” to be consistent with the language in R8. This is a violation of the FERC Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement”TOP-003-21. VSL for R1a. The sub-parts should be referenced in the VSL. (i.e. “The responsible entity did not include one of the required elements, per Requirement R1, Parts 1.1 though Parts 1.4, of the documented specification...”) b. There is no provision if an Applicable Entity fails to include three or more of the required elements. VSLs should be gradated to include failure of including both three and four sub parts.

Response: The SDT does not believe any of the VSLs referenced are in violation of FERC guideline 3. The VSLs do not have to use the exact language of the requirement to be consistent. However, the SDT does recognize there is value in using the same wording to the extent possible for consistency. For TOP-001-2, Requirement R2, the SDT has modified the VSL to use language that is more consistent with the requirement.

For TOP-001-2, Requirement R8, the SDT has replaced local area reliability with internal area reliability for the VSL.

TOP-001-2, R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% and less than or equal to 10% of the SOLs	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% and less than or equal to 15% of the	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less,

Organization				Yes or No	Question 4 Comment
	IROL, has been identified by the Transmission Operator as supporting its internal area reliability.	whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability.	Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability.		which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability.
For TOP-003-2, Requirement R1, the VSLs do include the sub-parts. However, they were not fully gradated and the SDT has added VSLs for missing three and four elements.					
TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.		11. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 12. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.
LG&E and KU Energy PPL Supply				No	The Time Horizons seem to be inconsistent with established NERC definitions. The VSLs need to be updated with language modified in the requirements
Response: Without additional specificity on Time Horizons, the SDT is unable to make any changes.					

Organization	Yes or No	Question 4 Comment
For the VSLs, the SDT has made numerous changes as specified in other comments.		
Western Electricity Coordinating Council Imperial Irrigation District Arizona Public Service Company	No	These same comments were submitted with our vote on the non-binding VRF and VSL pollWECC agrees with the VRFs and the majority of the VSLs. However, we beleive consideration of the following will improve the VSLs.TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs to not appear to address the situation where the responsible entity did not include three or more of the required elements of the documented specification for the data necessary for it to perform its required Operations Planning

Organization	Yes or No	Question 4 Comment
		Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?
Response: For the VSLs for TOP-001-2, Requirement R6, the SDT has made clarifying changes.		

TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	13. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 14. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated

Organization			Yes or No	Question 4 Comment
				communication channels between the affected entities.

For TOP-003-2, Requirement R1 VSLs, the SDT has added VSLs for missing three and four or more elements.

TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	15. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 16. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.

TOP-003-2, Requirement R4: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. No change made.

Organization	Yes or No	Question 4 Comment
Indeck Energy Services	No	TOP-001-2 R6: The VSL's do not consider the case of a small GOP (and possibly DP or LSE) which only affects the TOP or BA. The VSL needs

Organization	Yes or No	Question 4 Comment
		to reflect the significance of the planned outages. Planned outages of wind projects is of lower reliability significance than of large base load plants or black start units. The SDT needs to define the differences. Planned outages on GOP facilities that exceed the NERC Reportable Disturbance threshold for the BA would be Severe. Those between 75% & 100% of Reportable Disturbance would be High. Those between 50% and 75% of Reportable Disturbance would be Medium and all others would be Lower. TOP-003-2 R4: Only having Severe VSL avoids the difficult process of deciding what data is important. Data on outages of wind projects is of lower reliability significance than of large base load plants or black start units. The SDT needs to define the differences. Data on facilities that exceed the NERC Reportable Disturbance threshold for the BA would be Severe. Those between 75% & 100% of Reportable Disturbance would be High. Those between 50% and 75% of Reportable

Organization	Yes or No	Question 4 Comment
		Disturbance would be Medium and all others would be Lower.
Response: For TOP-001-2, Requirement R6, the SDT did attempt to address the case of the small Generator Operator, Transmission Operator or Balancing Authority by including the "x negatively impacted interconnected NERC registered entities".. It did not attempt to address small Distribution Providers or Load-Serving Entities as the requirement does not apply to them. While it may be true that wind projects are of lower significance to adequacy than base load units, the SDT did not make any changes based on the size of the unit as the size of the unit may not be relevant to its importance to the transmission security of reliability. TOP-003-2, Requirement R4: All data can be important given the right circumstances. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended represent failure of small sets of data due to RTU outages, transducer issues, etc. No change made.		
Colorado Springs Utilities	No	TOP-001-2 R8 & R9 VRFs should be "Low"TOP-002-3; R2 - IROLs should be "High" / SOLs should be "Low". R3 should be "Medium".
Response: The SDT believes the Medium VRF is appropriate for TOP-001-2, Requirements R8 and R9 as the SOLs that are identified by the Transmission Operator are important SOLs. To have a lower VRF, the requirement would have to be administrative in nature per the definition of VRF. No change made. The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. Thus, the VRFs for TOP-002-3, Requirement R2 were not changed. The SDT had modified the VRF for TOP-002-3, Requirement R3 to Medium. **TOP-002-3, R3**: Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor:Medium] [Time Horizon: Operations Planning]*		
Bonneville Power Administration	No	TOP-003-2: The proposed

Organization	Yes or No	Question 4 Comment
		sanctions seem disproportionate to the offense. If a BA fails to contact an entity that influences its operation, the failure does not seem to affect anything except the evaluation's accuracy to the offending BA. Furthermore, it seems unlikely that a deliberate omission would be made since it's in a BA's best interest to have accurate assessments. TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs to not appear to address the situation where the responsible entity did not include three or more of the required elements of the

Organization	Yes or No	Question 4 Comment
		documented specification for the data necessary for it to perform its required Operations Planning Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?

Response: TOP-003-2: The SDT is unsure of the specificity of your first comment. If you are referring to the percentage thresholds escalating quickly with 5% increments, these have been removed in favor of integer values.

TOP-001-2, Requirement R6: The SDT agrees with your comment and has made clarifying changes.

TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected	17. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 18. OR, The responsible entity did not notify four or more

Organization			Yes or No	Question 4 Comment
	entities.	affected entities.	entities.whichever is less.	negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

TOP-003-2, Requirement R1: The SDT agrees with your comment and has added VSLs for missing three and four or more elements.

TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	19. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 20. 21. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.

TOP-003-2, Requirement R4: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended represent

Organization	Yes or No	Question 4 Comment
failure of small sets of data due to RTU outages, transducer issues, etc. No change made.		
Southern Company	Yes	(Please note that these comments relate to TOP-001-2). It is suggested that the R1 VSL Severity text be written as an either/or statement. "entity either did not comply with (a directive) or did not inform ...."R1, as its currently written, gives an entity these two choices. The R2 VSL Severe test is more expansive than Requirement 2. To match R2, it is suggested that the test read" ...entity did not inform the TOP of its inability to comply" The R6 graduated VSLs, as written, are hard to understand. For a given outage, it is unclear how many "affected entities" there are likely to be. Also for R6, the OR statement has conflicting scope (i.e. planned outage of telemetry OR with planned outage of telemetering equipment).
Response: No change was made to TOP-001-2, Requirement R1 Severe VSL because the "and" condition is appropriate. If the responsible entity does not comply it must also inform the Transmission Operator. With an "or" condition, failure to comply would be a Severe VSL even if the responsible entity informs the Transmission Operator. The SDT agrees with your assessment for the VSL for TOP-001-2, Requirement R2 and has modified it.		

Organization			Yes or No	Question 4 Comment
TOP-001-2, R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
For the VSLs for TOP-001-2, Requirement R6, the SDT has made clarifying changes.				
TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	22. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 23. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
R6: The SDT agrees with your comment. Consistent with your comments in Question 1, the SDT changed telemetry to telemetering equipment.				

Organization	Yes or No	Question 4 Comment
Luminant Energy	Yes	
Luminant Power	Yes	
American Electric Power	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Lakeland Electric	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings Inc	Yes	
Cowlitz County PUD	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your support.		

5. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: The comments in this section are mostly repeats of comments submitted for other questions. No changes were made to requirements for comments made exclusively for this question.

Organization	Yes or No	Question 1 Comment
NIPSCO		The new standard appears to treat SOLs and IROLs in a similar manner, which should not be the case. Also, in TOP-003-2 R1 1.1 the second bullet may incorrectly bring non-BES distribution facilities into play.
Response: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. No change made. The bullets in TOP-003-2 have been deleted.		
Imperial Irrigation District		1. The proposed versions of the standards appear to remove the redundancy and provide better clarity to the requirements. However the period when the proposed standard becomes effective is cumbersome.PROPOSED - Suggest two effective dates be provided? For example:Regulatory approval 05/01/2011Effective Date 10/01/2013Effective Date “Not Requiring Regulatory Approval” 10/01/2013CURRENT - Effective Date: All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption. 2. Recommend that the RSAWS for these proposed standards be revised and posted when the standard versions become effective. 3. Data Retention - Could the Data Retention be displayed in a matrix format (see example below) EXAMPLE Function Requirement Evidence Retention Period TOP R1 Compliance with RC Directives Current Year + Previous Year BA R2 Compliance with TOP Directive Current Year + 1 Year GOP R3 Compliance with TOP Directive

Organization	Yes or No	Question 1 Comment
		Current Year + 1
Response: The effective date language used is provided by NERC Legal and is not subject to change by an SDT. No change made. RSAWs are not within the scope of the SDT. They are a compliance item. The format shown for data retention is supplied by the template used by SDTs. The SDT did not receive any other comments in this regard and is reluctant to change the format at this point in time. The SDT suggests that you send your request for a different data retention format to the NERC Standards Process Manager for consideration. No change made.		
City of Tacoma or Tacoma Public Utilities		Comments: Please provide the definitions for new terms in the first version of the Standards. Once they have been introduced and/or the standard is undergoing a new revision - they could be removed to the Glossary for future reference.
Response: The only new term used in the standards is Reliability Directive and that is supplied with the document. No change made.		
Arizona Public Service Co.	Ballot Comment	The need for the proposed “overarching” document is not necessary and appears cumbersome for many regions of the country such as the western interconnect.
Response: There is no mandate for an “overarching” document. The requirement is to provide document for any data that is needed for reliability. No change made.		
Wisconsin Energy Corp.	Ballot Comment	TOP-001 R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator, these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase “negatively impacted interconnected NERC registered entities” is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA’s of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse

Organization	Yes or No	Question 1 Comment
		Reliability Impact on another's area, hence an emergency there is somewhat circular. TOP-002 R3 the TOP should provide the plan to its RC and BA (s) in addition to notifying other entities of expected actions. The use of the phrase "all registered entities" is too open ended, and not limited to operational functions as it should be. In addition some actions may be required of entities not registered. TOP-003 R2 & R3 should not use the term monitored, the TOP or BA should distribute its data specification to all entities that are included in that specification to enable the proper Operational Planning Analyses and Real-time monitoring. R4 should not include both asset owners and operators, example generator xyz net output at the transmission interface needs to be the responsibility of one and only one entity to provide. Very confusing if both the GO and GOP have the same responsibility.

Response: TOP-001, R3: The requirement is referring to transmission problems so the Balancing Authority doesn't have to be notified. No change made.

R4: The Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made.

R6: The SDT has deleted Generator Operator from this requirement.

R10: This is a transmission function and not within the purview of the Balancing Authority so there is no need to notify them. No change made.

R3 & R5: Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this.

TOP-002, R3: The SDT has added the qualifier 'NERC' to the requirement to provide additional clarity.

TOP-003, R2 & R3: The Transmission Operator or Balancing Authority will only be requesting data from those it needs it from which will include all entities monitoring the equipment that the Transmission Operator or Balancing Authority is interested in. The SDT does not see any problem with the current language. No change made.

R4: The SDT sees no problem with listing asset operators and owners in this requirement. Each entity will have received a different and specific data specification from the Transmission Operator or Balancing Authority so there should be no problem. No change made.

END OF REPORT

Consideration of Comments

Real-time Transmission Operations Project 2007-03

The Real-time Transmission Operations Drafting Team thanks all commenters who submitted comments on the 6th draft of the standards for Real-Time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from December 14, 2011 through January 12, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 59 sets of comments, including comments from approximately 178 different people from approximately 103 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The SDT changed the following items due to industry comments received:

- TOP-001-2:
  - Requirement R1 – Allowed for plural Transmission Operators and deleted first instance of 'identified'
  - Requirement R6 – changed 'the' to 'its' Reliability Coordinator
  - Requirement R8 – changed 'internal area ' to 'internal to its Transmission Operator Area'; changed the Time Horizon to only Operations Planning
  - Requirement R10 – changed 'each' SOL to 'an' SOL
  - Data Retention – Changed voice recordings to 90 calendar days from three calendar months
- TOP-002-3:
  - Requirement R3 – changed 'internal area ' to 'internal to its Transmission Operator Area'
- TOP-003-2:
  - Applicability – added Distribution Provider
  - Requirement R2 – added analysis functions for the Balancing Authority
  - Requirement R3 – Cited the tie to Requirement R1 and made the language in Requirement R3 consistent with that in Requirement R1
  - Requirement R4 - Cited the tie to Requirement R2 and made the language in Requirement R4 consistent with that in Requirement R2
  - Requirement R5 – added Distribution Provider
  - Measures M3 and M4 – clarified the web posting item of evidence

In addition, the SDT changed VSLs for TOP-001-2, Requirements R1, R3, R5, R8, and R10, plus VSLs for TOP-002-3, Requirement R3, and TOP-003-2, Requirements R1, R2, R3, and R4.

After the Quality Review was completed, the SDT made the following changes:

- TOP-001-2:
  - Requirement R1 – eliminated the plural context
  - Requirement R3 – clarified the plurality context
  - Requirement R5 – clarified the list of items
  - Measures – added attestations as evidence when no event has occurred
  - Compliance section – updated to latest revision
  - VRF justifications – moved away from using proposed requirements where possible
  - Requirement R1 VSL – clarified language
  - Requirements R3, R5, and R6 VSLs – added percentages
  - Requirement R8 – added language to exactly match requirement
  - Issues resolution – clarified language
  - Implementation Plan – clarified language
- TOP-003-2:
  - Requirements R1 and R2 – deleted use of 'required'
  - Measures M3 and M4 – corrected typo
  - Compliance section – updated to latest revision
  - VRF justification - moved away from using proposed requirements where possible

Minority comments included:

- Use of Reliability Directive – Some commenters object to the use of an unapproved definition, Reliability Directive, in TOP-001-2. They feel that it presents coordination problems and could cause a change to the standard if the definition is changed during its balloting. The SDT explained that it was working closely with Project 2006-06 which is developing the definition. Indeed, there are several members of the RTOSDT who are also on the RCSDT. The SDT also assures commenters that the need to coordinate filing the two projects, 2006-06 and 2007-03, has been forwarded to NERC management.
- There was concern about possible double jeopardy with TOP-003-2, Requirements R1/R3 and R2/R4. The SDT explained that double jeopardy should not be a concern as the two requirements represent two different actions: one to create the specification and one to distribute it. The two separate and distinct actions mean that there are two distinct reliability outcomes and that two separate requirements are needed.

TOP-001-2 did not pass initial ballot. The SDT made several changes to this standard to respond to comments and negative ballots. The SDT is recommending that TOP-001-2 be approved for a successive ballot.

TOP-002-3 passed its initial ballot but the SDT made a change to the effective date in response to comments. Therefore, the SDT is recommending that TOP-002-3 be advanced to a successive ballot.

TOP-003-2 did not pass initial ballot. The SDT made several changes to this standard to respond to comments and negative ballots. The SDT is recommending that TOP-003-2 be approved for a successive ballot.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC	8
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Chantel Haswell	FPL Group, Inc.	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Robert Rhodes	Southwest Power Pool	SPP	2
3.	Ashley Stringer	OMPA		4
4.	John Allen	City utilities of Springfield	SPP	1, 4
5.	Michelle Corley	CLECO	SPP	1, 3, 5
6.	Ron Gunderson	NPPD	MRO	1, 3, 5
7.	Terri Pyle	OGE	SPP	1, 3, 5
8.	Valerie Pinamonti	AEP	SPP	1, 3, 5
9.	Tiffani Lake	Westar	SPP	1, 3, 5, 6
10.	Jim Useldinger	KCPL	SPP	1, 3, 5, 6
11.	Mahmood Safi	OPPD	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Joe O'Brien	NIPSCO	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe O'Brien	NIPSCO	RFC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Annie Lauterbach	Bonneville Power Administration	X		X		X	X				

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Loepker	Dittmer Dispatch	WECC	1
2.	John Anasis	Technical Operations	WECC	1
3.	Theodore Snodgrass	Monroe Dispatch	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Albert DiCaprio	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Thompson	AESO	WECC	2
2.	Gary DeShazo	CAISO	WECC	2
3.	Steven Myers	ERCOT	ERCOT	2
4.	Ben Li	IESO	NPCC	2
5.	Matt Goldberg	ISO-NE	NPCC	2
6.	Bill Phillips	MISO	RFC	2
7.	Donald Weaver	NBSO	NPCC	2
8.	Greg Campoli	NYISO	NPCC	2
9.	Patrick Brown	PJM	RFC	2
10.	Charles Yeung	SPP	SPP	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Reed	FE	RFC	
2.	Kevin Querry	FE	RFC	
3.	Bill Duge	FE	RFC	
4.	Brian Orians	FE	RFC	
5.	Gary Pleiss	FE	RFC	
6.	Sherri Rhodes	FE	RFC	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Juel Fugett	IID	WECC	1, 3, 4, 5, 6
2.	Alfonso Juarez	IID	WECC	1, 3, 4, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team		X								

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
1. Jonathan Hayes	Southwest Power Pool	SPP	2
2. Robert Rhodes	Southwest Power Pool	SPP	2
3. Ashley Stringer	OMPA		4
4. John Allen	City utilities of Springfield	SPP	1, 4
5. Michelle Corley	CLECO	SPP	1, 3, 5
6. Ron Gunderson	NPPD	MRO	1, 3, 5
7. Terri Pyle	OGE	SPP	1, 3, 5
8. Valerie Pinamonti	AEP	SPP	1, 3, 5
9. Tiffani Lake	Westar	SPP	1, 3, 5, 6
10. Jim Useldinger	KCPL	SPP	1, 3, 5, 6
11. Mahmood Safi	OPPD	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Connie Lowe	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Garton		NPCC	5
2. Michael Gildea		MRO	5
3. Louis Slade		RFC	5, 6
4. Michael Crowley		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Harold Wyble	Kansas City Power & Light	SPP	1, 3, 5, 6
2. Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6
3. Jessi Tucker	Kansas City Power & Light	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Gerald Beckerele	SERC OC Standards Review Group	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Vicky Budreau	Santee Cooper	SERC	1, 3, 5, 9
2. Cindy Martin	Southern	SERC	1, 3, 5
3. Bob Dalrymple	TVA	SERC	1, 3, 5, 9
4. Merritt Castello	Southern	SERC	1, 3, 5
5. Scott Brame	NCEMC	SERC	3, 4
6. Tim Lyons	OMU	SERC	1, 3, 5
7. Jake Miller	Dynegy	SERC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Marc Butts	Southern	SERC	1, 3, 5
9.	Mike Hirst	Cogentrix	SERC	5, 6
10.	Joel Wise	TVA	SERC	1, 3, 5, 9
11.	Andy Burch	EEI	SERC	1, 5
12.	Byron Thomasson	PowerSouth	SERC	1, 3, 5, 9
13.	Tim Hattaway	PowerSouth	SERC	1, 3, 5, 9
14.	Travis Sykes	TVA	SERC	1, 3, 5, 9
15.	Randy Hubbert	Southern	SERC	1, 3, 5
16.	Dwayne Roberts	OMU	SERC	1, 3, 5
17.	Hugh Francis	Southern	SERC	1, 3, 5, 9
18.	Larry Akens	TVA	SERC	1, 3, 5, 9
19.	Mike Hardy	Southern	SERC	1, 3, 5
20.	Greg Rowland	Duke	SERC	1, 3, 6
21.	Sam Holeman	Duke	SERC	1, 3, 6
22.	Melinda Montgomery	Entergy	SERC	1, 3
23.	Brad Young	LGE/KU	SERC	1, 3, 6
24.	Carter Edge	SERC	SERC	10
25.	Steve McElhaney	SMEPA	SERC	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Will Smith	MRO-NSRF	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Webb	WPS	MRO	3, 4, 5, 6
4.	Jodi Jenson	WAPA	MRO	1, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Alice Ireland	Xcel/NSP	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
9.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
10.	Scott Nickels	RPU	MRO	4
11.	Terry Harbour	MEC	MRO	3, 5, 6, 1
12.	Marie Knox	MISO	MRO	2

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

13.	Lee Kittelson	OTP	MRO	1, 3, 4, 5
14.	Scott Bos	MPW	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Brenda Powell	Constellation Energy						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	C. J. Ingersol	Constellation Energy Control & Dispatch	SERC	3
2.	Amir Hammad	Constellation Power Source Generation, Inc.		5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Jason Marshall	ACES Power Marketing Member Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Watson	Old Dominion Electric Cooperative	SERC	3, 4, 5, 6
2.	Mohan Sachdeva	Buckeye Power	RFC	4, 5, 6
3.	Bob Solomon	Hoosier Energy	RFC	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
16.	Individual	Eric Ruskamp	Lincoln Electric System (LES)	X		X		X	X				
17.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
18.	Individual	Brent Ingebrigtson	LG&E and KU Serivces	X		X		X	X				
19.	Individual	Neil Phinney	Georgia System Operations			X	X						
20.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
21.	Individual	Shaun Anders	City Water Light and Power (CWLP) - Springfeild - IL	X		X		X					
22.	Individual	Jonathan Appelbaum	United Illuminating Company	X									
23.	Individual	Jonathan Appelbaum	United Illuminating	X									
24.	Individual	Rich Vine	California Independent System Operator		X								
25.	Individual	Thomas E Washburn	FMPP						X				
26.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
27.	Individual	Howard Rulf	We Energies			X	X	X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
29.	Individual	Jeff Longshore	Luminant Energy Company, LLC						X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
30.	Individual	DAVID DOCKERY	Associated Electric Cooperative, Inc.	X		X		X	X				
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Robert Roddy	Dairyland Power Cooperative	X		X		X					
33.	Individual	Kathleen Goodman	ISO New England Inc.		X								
34.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
35.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP - Occidental Chemical Corporation					X					
36.	Individual	David Thorne	Pepco Holdings Inc	X		X							
37.	Individual	Mahmood Safi	Omaha Publc Power District	X		X		X	X				
38.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
39.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
40.	Individual	Dana Showalter	E.ON Climate & Renewables					X					
41.	Individual	Don Jones	Texas Reliability Entity										X
42.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
43.	Individual	Rich Salgo	NV Energy	X		X		X	X				
44.	Individual	Gregory Campoli	New York Independent System Operator		X								
45.	Individual	Martin Bauer	US Bureau of Reclamation					X					
46.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
47.	Individual	Anthony Jablonski	ReliabilityFirst										X
48.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
49.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
50.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
51.	Individual	Edvina Uzunovic	The Valley Group, a Nexans Company										
52.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
53.	Individual	Terri Pyle	Oklahoma Gas and Electric	X		X		X					
54.	Individual	Julie Lux	Westar Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
55.	Individual	Thad Ness	American Electric Power	X		X		X	X				
56.	Individual	Brenda Truhe	PPL Electric Utilities	X									
57.	Individual	Bill Keagle	BGE	X									
58.	Individual	Kirit S. Shah	Ameren	X		X		X	X				
59.	Individual	Jason Snodgrass	GTC	X									

1. **The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Comments were made on all Requirements within TOP-001-2. Most of these comments indicated individually preferred language that the SDT did not feel improved clarity, and were therefore not adopted.

In response to a large group of comments, Requirement R8 was modified to replace the phrase "its internal area reliability" with "reliability internal to its Transmission Operator Area".

The SDT clarified in its response that the term 'continuous duration' has its common meaning.

In response to comments, minor changes were made to Requirements R1, R6, and R10 to improve clarity.

The Time Horizon for Requirement R8 was changed to Operations Planning only.

Conforming changes were made to the respective Measures, VSLs, and VRFs.

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless ~~-~~such actions would violate safety, equipment, regulatory, or statutory requirements.

R6. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or ~~each~~an SOL identified in Requirement R8, has been exceeded.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
California ISO	Negative	R6 requires Balancing Authorities and Transmission Operators to notify "negatively impacted interconnected NERC registered entities" of planned outages. This term is not specific enough to narrow down who must be notified. For instance, with this open-ended wording it could be construed that BAs would have to notify LSEs and DPs in their areas which would be an onerous task. We would recommend staying with "negatively-affected BAs and TOPs." The wording in R9 is confusing and is not specific enough to ensure compliance. In particular the requirement prohibits operation outside any SOL "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based." However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. In addition, under R9 and M9, how will the word "continuous" be defined or measured? This is extremely important to understand because the VSL table states the following as Severe for R9: "The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria." It seems that the effective date should be set much sooner than 24 months following approval since there are basically no new requirements associated with this standard. Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Response: Regarding Requirement R6, since telemetry has definite parties at each end, the Balancing Authority or Transmission Operator with the telemetry issue is in the best position to know which other parties are affected by its telemetry outages. No change made. Regarding Requirement R9, ratings include the element of time. In view of the current NERC definitions of IROLs and SOLs, the language is correct as is written. The definition of IROLs describes the negative results that could occur when an IROL is exceeded		

Organization	Yes or No	Question 1 Comment
for a time greater than its T_v. The definition for SOL does not have this language, so no "... instability, uncontrolled separation(s) or cascading outages...." happens upon the exceedance of an SOL that is not an IROL. No change made. In Requirement R9 and Measure M9, 'continuous duration' has its common meaning. No change made. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months for all requirements except the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Colorado Springs Utilities	Negative	Colorado Springs Utilities (CSU) appreciates the work of the SDT to reconcile the various requirements into TOP-001, -002, & -003; and this opportunity to comment. The language of this group of standards has improved much with each draft. However, CSU continues to be concerned with the creation of an apparently "special" class of SOL in TOP-001-3 R8, R9 & R11 - creating what seems to be a middle category between "run of the mill" SOLs and IROLs; with no guidance, whatsoever, on how SOLs should qualify for or be excluded from this intermediate treatment. FAC-011 & FAC-014 already adequately cover identification and communication of SOLs and IROLs, and CSU believes that, if any additional SOL categories need be created, they should be more appropriately addressed in those standards. Additionally, there is no definition and a lack clarity for the concept of "supporting internal area reliability". In previous Considerations, the SDT has stated, "Requirements R8 and R10 were added due to comments from a significant portion of the industry during the extensive posting process of these standards." But, as the SDT has acknowledged, "There is still some debate as to what is meant by internal area reliability." The SDT continued, "The SDT continues to believe, as stated in previous responses, that the Transmission Operator is best suited to determine what affects its internal area and the resolution of those issues are best left to the Transmission Operator." If best left to the Transmission Operator, then one wonders why this "special" SOL should be added to the Standard? This concept is obviously causing much consternation amongst responding entities and has

Organization	Yes or No	Question 1 Comment
		the makings of, at best, a moot requirement (if no-one identifies any special SOLs) or, at worst, a compliance minefield - considering the questions that will come to an auditor's mind when trying to assess compliance with these requirements as written. CSU also continues to feel strongly, despite protestations of the SDT to the contrary, that R7/R9 and R11 create a double jeopardy waiting to happen, and would best be appropriately combined.
Response: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. These requirements embed that concept in the standard. No change made. The SDT has replaced 'internal area reliability' with 'reliability within its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. These requirements are the core Transmission Operator requirements that assure continued reliable operation of the BES. If the Transmission Operator acts or directs others to act to mitigate, as in Requirement R11, but is unable to return the facility within its IROL with a time T_v or its SOL within its time criteria, then the Transmission Operator is compliant with Requirement R11 and noncompliant with either Requirement R7 or Requirement R9, as dictated by the exact circumstances. If the Transmission Operator fails to act or fails to direct others to act, as in Requirement R11, then it is noncompliant with both Requirement R11 and either Requirement R7 or Requirement R9, as dictated by the exact circumstances. This is not double jeopardy. No change made.		
MidAmerican Energy Co.	Negative	MidAmerican has concerns about TOP-001 R8 and R9. It appears the drafting team has unintentionally created an undefined subset or class of SOLs that are roughly equivalent to IROLs. More clarification is needed to clearly state that the new class of SOLs is a subset of all SOLs and not all

Organization	Yes or No	Question 1 Comment
		SOLs. MidAmerican recommends that R8 be modified to strike “each SOL” and replaced with “subset of Reliability Coordinator defined SOLs”. Otherwise auditors could argue that the NERC definition of a SOL includes all NERC BES devices since they all have thermal and voltage limits and therefore all NERC BES facilities apply to R8 and R9.
Response: The SDT believes that the language in Requirement R8 is clear. This requirement only applies to that subset of SOLs that are deemed to be more significant to the Transmission Operator than the typical SOL. This subset was intentionally created by the SDT in response to industry comments. The Transmission Operator must define its SOLs consistent with the Reliability Coordinator’s SOL methodology per FAC-014-2, Requirement R2. Thus, each SOL is defined per the Reliability Coordinator’s methodology. No change made.		
Muscatine Power & Water	Negative	Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the Standards Drafting Team requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9? Note that the SOL definition has a thermal rating component in it and we are not sure how you can’t draw SOLs into the same category as IROLs unless you clearly indicate these standards only apply to a subset.
Response: Typically, ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. For SOLs, the time limit varies according to the facility ratings used in the development of the SOL. No change made.		
Northeast Utilities	Negative	TOP-001-2 is referencing a NERC definition for “Reliability Directive” which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of “Reliability Directive” would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board”

Organization	Yes or No	Question 1 Comment
		usable definition.
Roger C. Zaklukiewicz	Negative	There currently is a definitionn for "Relibility Directive" which is listed in the Definition of Terms used in Standards. It is my understanding that the definition of the term "Relibility Directive" is being reviewed and probably will be rewritten/modified by the Relibility Coordinator Standards Drafting Team (Project 2006-06). Associated with this effort, is clarification of the term "Adverse Relibility Impact" which may have a significant impact on how TOP-001-2 is interpreted and administered throughout the industry. I believe the work of the Project 2006-06 Team should be coordinated with this initiative so that we have a greater level of certainty upon which we are casting a vote.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team as well.		
Oncor Electric Delivery	Negative	For R6- Oncor Electric Delivery respectfully submits this response as it does not believe that the proposed language will provide a coordinated communication effort in the event of a planned outages of telemetry, control equipment and associated communication channels. In addition, the term "negatively impacted interconnected registered entities" is too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity.
Response: The SDT is unsure of the intent of this comment, since no suggested alternative language was proposed. The SDT continues to believe that the Transmission Operator is in the best position to know which other parties are affected by its telemetry outages and it is not necessary to include the Reliability Coordinator into this item. Owner/operators of affected telemetry equipment have traditionally coordinated these outages. No change made.		

Organization	Yes or No	Question 1 Comment
Southwest Power Pool, Inc.	Negative	R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Response: The SDT made a conscious decision to raise the bar on IROLs to incorporate the T_v limit. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made.		

Organization	Yes or No	Question 1 Comment
Requirement R9 does not apply to SOLs which are not identified in Requirement R8. No change made. The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. The SDT agrees. Conforming change made. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Tampa Electric Co.	Negative	Definitions for Reliabilty Directive should be with this ballot since it is the first to be balloted Is R4 to be interpreted that I must drop Firm load if the requesting TOP is droping Firm load. The words would imply that so I can't vote in the affirmative.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team also. No change made. Shedding firm load is one of the tools for maintaining the reliability of the BES. However, this does not mean that if the initiating Transmission Operator drops load, that the cooperating Transmission Operator must necessarily drop load. It is possible, however, that two or more Transmission Operators may need to shed load to resolve an operating issue. This requirement is intended to assure that the initiating Transmission Operator cannot demand that a cooperating Transmission Operator execute emergency actions that the initiating Transmission Operator has not been willing or able to implement. No change made.		
Northeast Power Coordinating	No	Requirements R1 and R2 should not be separate. Having them broken out

Organization	Yes or No	Question 1 Comment
Council		in this manner could potentially put entities in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then Requirement R4 should be broken down into two requirements. Requirement R4 states that information is being requested, AND is available. TOP-001-2 R2 states: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations] ☐ seems problematic and further work needs to be done on this requirement to ensure that the proper intent is codified. The intent we believe to be ..immediately upon recognition of the inability to perform a Reliability Directive within the stipulated or understood timeframe would result in informing the TO. The concern exists that an entity might be able to perform the directive but may not within the proper timeframe of the TOPs need. In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning Analysis as "An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much

Organization	Yes or No	Question 1 Comment
		as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency? The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency does not occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning.Suggest rewording Requirement R3 to:R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness

Organization	Yes or No	Question 1 Comment
		there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard. Double jeopardy is introduced with TOP-001 R8 and FAC-014 R5.2. Fac-014 R5.2 states "The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area"; while TOP-001 R8 states "Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis."

Response: There is no double jeopardy with separate requirements. If an entity receives a Reliability Directive and for the reasons stated in Requirement R1 can't comply with it, it is compliant with Requirement R1. If the entity fails to inform the issuer of the Reliability Directive, it is non-compliant with Requirement R2. Requirement R1 does not require the entity to inform. No change made.

As 'requested and available' is a descriptor and not separate functions. No change made.

Unless stated otherwise, a Reliability Directive should be assumed to require immediate or as soon as practicable response. The terms "immediate" and "as soon as practicable" have been debated without resolution in other projects and have been determined to be unmeasureable. The SDT sees no way to place a measurable timeframe on responding to a Reliability Directive. No change made.

The SDT sees no additional clarity from the suggested change "known or expected to be affected". This language was chosen to cover all situations, including an ongoing event. No change made. The suggested change to remove "actual" is not adopted for the same reason: An entity could be in the midst of an on-going emergency that will continue to be present in the next-day, so the wording is correct. No change made.

Organization	Yes or No	Question 1 Comment
R4: The SDT sees no additional clarity from the suggested change. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. The subset of SOLs in this requirement requires special handling, thus, this requirement does not introduce double jeopardy. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Orange and Rockland Utilities, Inc.	No	Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then they should break out R4 into two requirements. Who's to say that the information is requested AND available? In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency

Organization	Yes or No	Question 1 Comment
		as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard.</td></tr>
<tr><td colspan="3">Response: There is no double jeopardy with separate requirements. If an entity receives a Reliability Directive and for the reasons stated in Requirement R1 can't comply with it, it is compliant with Requirement R1. If the entity fails to inform the issuer of the Reliability Directive, it is non-compliant with Requirement R2. Requirement R1 does not require the entity to inform. No change made.

As 'requested and available' is a descriptor and not separate functions. No change made.

This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid a noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made.

The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8.

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.</td></tr>
<tr><td>Consolidated Edison Co. of NY, Inc.</td><td>No</td><td>Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then they should break out R4 into two requirements. Who's to say that the information is requested AND available? In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to:R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission

Organization	Yes or No	Question 1 Comment
		Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard.

Response: There is no double jeopardy with separate requirements. If an entity receives a Reliability Directive and for the reasons stated in Requirement R1 can't comply with it, it is compliant with Requirement R1. If the entity fails to inform the issuer of the Reliability Directive, it is non-compliant with Requirement R2. Requirement R1 does not require the entity to inform. No change made.

As 'requested and available' is a descriptor and not separate functions. No change made.

The SDT sees no additional clarity from the suggested change "known or expected to be affected". This language was chosen to

Organization	Yes or No	Question 1 Comment
cover all situations, including an ongoing event. No change made. The suggested change to remove "actual" is not adopted for the same reason: An entity could be in the midst of an on-going emergency that will continue to be present in the next-day, so the wording is correct. No change made. The SDT sees no additional clarity from the suggested change. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid a noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Southwest Power Pool Regional Entity	No	Action is only required by the proposed standards if a real time violation of a previously identified SOL occurs. No action is required in a preventative manner and no action is required as a result of a real time problem that was not identified by the Operational Planning Assessment. R5 should include notifying the RC of anticipated SOL violations. Addition in quotes. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact "or SOL violation" on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures

Organization	Yes or No	Question 1 Comment
		and changes in generation, Transmission, or Load.
Response: The 'anticipated' language addresses preventative. An assessment can happen at any time. It is not necessary to take action on an SOL. The definition of IROL describes the negative results that could occur when an IROL is exceeded for a time greater than its T_V. The definition for SOL does not have this language, so no "... instability, uncontrolled separation(s) or cascading outages...." happen upon the exceedance of an SOL that is not an IROL. No change made. The SDT does not agree. Adverse Reliability Impact captures the intent of the communications required in Requirement R5. No change made.		
US Army Corps of Engineers	Negative	Issue: Upon review of the NERC Glossary of Terms, please drop the from or Adverse Reliability Impacts within the definition of a Reliability Directive. Issue: M1; It is not necessary to repeat the Requirement within the Measure. Recommend unless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1, be removed from this Measure. Issue: M4; It is not necessary to repeat the Requirement within the Measure. Recommend unless such actions would violate safety, equipment, regulatory, or statutory requirements, be removed from the Measure. Issue: Upon review, it is noted that ˜Coordination of has been struck from Purpose, however not removed from the Title of the Standard. Recommend changing ˜interconnection in the Purpose to ˜Bulk Electric System (BES) Issue: R3: The statement Transmission Operators that are known or expected to be affected the use of known or expected is redundant. Recommend removing ˜known or expected and have the requirement rewritten as follows: Issue: R3: Each Transmission Operator shall inform its Reliability Coordinator

Organization	Yes or No	Question 1 Comment
		and Transmission Operators to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. Issue: R8: The statement its internal area reliability should be clarified to state: R8: Each Transmission Operator shall inform its Reliability Coordinator of each of its SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its Transmission Operators area based on its assessment of its Operational Planning Analysis. Issue: M8: statement its internal area reliability should be clarified to state: has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you cant draw SOLs into the same category as IROLs unless you clearly indicate these standards only apply to a subset.

Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration. No change made.

M1 and M4: Requirement language is usually repeated in Measures. No change made.

Title has been corrected.

Interconnection is the correct term in the Purpose, as Transmission Operators in different interconnections are not required to coordinate actions.

The SDT sees no additional clarity from the suggested change. No change made.

Organization	Yes or No	Question 1 Comment
The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made.		
Bonneville Power Administration	No	Comments: Given the potential uncertainty regarding the 30 Minute Rule, BPA suggests adding more clarity to the standard TOP-001-2 as the new draft could be interpreted to mean that one would need to get the flows below the SOL immediately. BPA believes this is not practical because it takes a definite amount of time to change schedules, move generation, or perform other actions in order to reduce loadings on facilities. BPA believes the new draft should include guidance as to how much time the BA or Transmission Operator would be allowed in order to reduce flows when there is an SOL violation. BPA suggests that more clarity be provided and/or the 30 minute rule be added back to the standard.
Response: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made. Additionally, the SDT believes including the “a violation of the Facility Rating or Stability criteria upon which it is based” is superior to how the standard is written today. The currently in force TOP-004-2, Requirement R2 is written without time limits or criteria and could be interpreted as requiring flows to be mitigated immediately for an IROL and SOL as well.		
ISO/RTO Standards Review Committee	No	Instead of using ‘its’ TOP in R1 we suggest using ‘a’ TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If

Organization	Yes or No	Question 1 Comment
		this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Southwest Power Pool Reliability Standards Development Team	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency

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ISO New England Inc.	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no

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		N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
BGE	No	BGE concurs with ISO/RTO Standards Review Committee Position:Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For

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		example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7.We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Pepco Holdings Inc	No	PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Nebraska Public Power District	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. In R3, suggest rewording as "Each Transmission Operator shall inform its Reliability Coordinator, and other Transmission Operators, of each actual and anticipated Emergency that they are known or expected to be affected by, based on its assessment of its Operational Planning Analysis". The

Organization	Yes or No	Question 1 Comment
		existing language doesn't clearly specify what is to be communicated with affected entities. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9, even in situations where the inititating event was outside of design criteria. Current language allows exceedance of an IROL for a specific time, but does not appear to give any time to readjust the system for the less severe SOLs. This does not seem reasonable. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8?This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? Suggest "Each Transmission Operator shall inform its Reliability Coordinator of each SOL identified by the Transmission Operator as supporting the reliability of its Transmission Operator Area". With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC.

Organization	Yes or No	Question 1 Comment
		Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.

Response: R1: The SDT agrees and has adjusted the language to allow for multiple TOPs.

> **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless ~~-~~such actions would violate safety, equipment, regulatory, or statutory requirements.

R3: The SDT does not see that the suggested change improves clarity. No change made.

R9: SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. Additionally, if the SOL was not identified in Requirement R8, then Requirement R9 does not apply to it. No change made.

R8 and R9: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. The subset of SOLs in this requirement was created in response to industry comments that SOLs should not be completely removed from the standard.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R10 and R11: Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made.

R6: The SDT agrees. Conforming change made.

> **R6**. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-

Organization	Yes or No	Question 1 Comment
003-2, Requirements R1 and R2 which will be 10 months.		
Imperial Irrigation District (IID)	No	R2 - This requirement requires the BA, GOP, and LSE to notify the TOP if it cannot comply with the Reliability Directive. (Comment) - Should include the language that the entity is not able to comply with the Reliability Directive due to violation of safety, equipment regulatory or statutory requirements. R7 - This requirement requires that the TOP not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL (Comment) - Should the language in the requirement also include the reference to SOLs since WECC does not have IROLs? R8 - This requirement requires the TOP to inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis (Comment) - Remove "which, while not IROL" from the requirement language and add "that" before "have been identified". This would make the statement more clear. R9 - This requirement requires that the TOP not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. (Comment) - Define Continuous. What would constitute a violation? 5 minutes, 10 minutes? In some cases corrective action requires participation and/or direction from the Reliability Coordinator and this could take up to 30 minutes. Recommend leaving the 30 minute duration in place. (Comment) - Recommend referencing R7 if the SOLs are included in the requirement. R10 - This requirement requires the TOP to inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each

Organization	Yes or No	Question 1 Comment
		SOL identified in Requirement R8, has been exceeded. (Comment) - the language should include the reference to R7 if the SOL is included in the requirement. (Comment) - Recommend including ~~time frame~~timeframe for notification to the Reliability Coordinator to include "30 minutes or less" R11 - This requirement requires the TOP to act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Measures or of an SOL identified in Requirement R8. (Comment) - Since only the Reliability Coordinator has the authority to direct others to take action; should the language be revised in the following manner; "The TOP shall take action to mitigate both the magnitude and duration of exceeding an IROL or an SOL as identified in R7 and R8 that occur within its TOPs area. The TOP shall appeal to the Reliability Coordinator to direct other TOPs in mitigating both magnitude and duration on interconnected facilities on the Bulk electric System".

Response: Requirement R2 covers all situations where the Reliability Directive can't be carried out. This requirement is simply to 'inform' and at the time in question the reason is not critical. The reason can be sorted out later. No change made.

In view of the current NERC definitions of IROLs and SOLs, the language is correct as is. The definition of IROLs describes the negative results that could occur when an IROL is exceeded for a time greater than its T_V. The definition for SOL does not have this language, so no "... instability, uncontrolled separation(s) or cascading outages...." happens upon the exceedance of an SOL that is not an IROL. No change made.

The SDT disagrees and believes the requirement needs to be clear that it applies to non-IROL SOLs since IROLs by definition are a subset of SOLs. However, the language in Requirement R8 was modified for improved clarity due to other comments.

> **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

Ratings include the element of time. 'Continuous duration' has its common meaning. The SOLs in question are in reference to Requirement R8, not Requirement R7. The SDT received a substantial amount of comments during the last posting to remove the

Organization	Yes or No	Question 1 Comment
30 minute timeframe on SOLs. No change made. The SOLs in question are in Requirement R8 which is referenced in Requirement R10. No change made. Requirement R10 notification is after the fact and no timeframe is necessary. No change made. One Transmission Operator can reach out to another Transmission Operator in Requirement R11 and it would be expected that the other Transmission Operator would respond per Requirement R4. The Reliability Coordinator always maintains ultimate responsibility for multi- Transmission Operator areas as per the IRO standards and would be expected to step in as needed. This set of requirements is not a procedure. No change made.		
Kansas City Power & Light	No	Requirements R3 & R5 requires TOP's to notify all other "affected" TOP's in instances of emergency or Adverse Reliability Impact. The term "affected" is a debatable condition and subject to interpretation. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Recommend the requirement be modified to alert other TOP's whenever a TOP in an emergency or Adverse Reliability Impact operating condition becomes aware of operating conditions that would result in exceeding an SOL or IROL operating limits under N-1 contingency conditions for other TOP facilities. Modifications for these two requirements will result in subsequent changes to the Measures and VSL's for requirements R3 & R5. In requirements R9 and R11 the 30-minute transition from an unknown operating state to a known state is lost for operating from an n-1 state to a n-2 state therefore leading to an immediate violation of R9 if the facility rating is exceeded. Also, the inclusion of IROL's in R10 and R11 makes these requirements confusing as to who is responsible for mitigation, IROL's should be removed from here as they are considered in the IRO requirements, these requirements should only address SOL's. Requirement R8 uses the term "continuous duration". The term "continuous duration" will be subject to interpretation as to its meaning and intent. As proposed, this requirement will be difficult to audit and will cause

Organization	Yes or No	Question 1 Comment
		uncertainty in the industry. Also, a draft Reliability Directive definition is included in this standard but needs approval in the COM-002 standard, what if COM-002 does not get approved?
Response: The SDT believes the use of the defined terms in the requirements covers the situation appropriately. No change made. By definition an IROL violation occurs when the IROL limit is exceeded for duration greater than T_v. Thus, it must be the time duration. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made. Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made. This is actually referring to Requirement R9, not Requirement R8. 'Continuous duration' has its common meaning. No change made. Reliability Directive: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will also be coordinated with that team.		
SERC OC Standards Review Group	No	We suggest that the definition of Reliability Directive should be modified as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or “an event that results in Bulk Electric System instability or Cascading”. We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition. We suggest the Standard Drafting Team further clarify or define the term “supporting internal area reliability” as an aid in demonstrating compliance and how this requirement enhances reliability.

Organization	Yes or No	Question 1 Comment
		We suggest including “Real-time Assessments” in this standard to clarify Operations Planning and same day operations time horizons (Requirement 8). We request that the drafting team review and explain the differences in the time horizons for Requirements 3, 5 and 8.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration. No change made. The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. A Transmission Operator cannot operate with its IROLs (Requirement R7) and SOLs (Requirement R9) without performing Real-time assessments. As a result, the SDT does believe that Real-time assessments are included. No change made. Requirement R3 is day ahead so the horizon is operation planning. Requirement R5 is in real-time so the horizons represent those time horizons. Requirement R8 should be Operations Planning only and the SDT has made this change.		
MRO-NSRF	No	Issue: Upon review of the NERC Glossary of Terms, please drop the “s” from “...or Adverse Reliability Impacts” within the definition of a Reliability Directive. Issue: M1; It is not necessary to repeat the Requirement within the Measure. Recommend “unless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1”, be removed from this Measure.

Organization	Yes or No	Question 1 Comment
		Issue: M4; It is not necessary to repeat the Requirement within the Measure. Recommend “unless such actions would violate safety, equipment, regulatory, or statutory requirements”, be removed from the Measure. Issue: Upon review, it is noted that ‘Coordination of’ has been struck from Purpose, however not removed from the Title of the Standard. Recommend changing ‘interconnection’ in the Purpose to ‘Bulk Electric System (BES)’ Issue: R3: The statement “...Transmission Operators that are known or expected to be affected...” the use of “known or expected” is redundant. Recommend removing ‘known or expected’ and have the requirement rewritten as follows: Issue: R3: Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. Issue: R8: The statement “...its internal area reliability...” should be clarified to state: R8: Each Transmission Operator shall inform its Reliability Coordinator of each of its SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its Transmission Operators area based on its assessment of its Operational Planning Analysis. Issue: M8: statement “...its internal area reliability...” should be clarified to state:”...has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis...” Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you can’t draw SOLs into

Organization	Yes or No	Question 1 Comment
		the same category as IROLs unless you clearly indicate these standards only apply to a subset.
Response: "Reliability Directive" is under the auspices of the RC SDT (Project 2006-06). This comment has been passed on to that team. Plural versions of the NERC definitions are regularly used throughout the standards. M1: Requirement language is usually repeated in Measures. No change made. M4: Requirement language is usually repeated in Measures. No change made. R3: The SDT sees no additional clarity from the suggested change. No change made. R8: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. SOLs: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made.		
Constellation Energy	No	The definition of Reliability Directive is an improvement but the definition must capture the identification concept that is reflected in the Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. We suggest the following revision to the definition and it should follow through to Project 2006-06 (COM-002-3 and IRO-001-3), eventually being added to the Reliability Standards Glossary of Terms. A communication identified as a Reliability Directive by a Reliability Coordinator, Transmission Operator, or Balancing Authority to initiate action by the recipient to address an Emergency or Adverse Reliability Impact. The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. CCG, CECD and CPG agree with ISO/RTO Standards Review Committee Position: Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is

Organization	Yes or No	Question 1 Comment
		possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well

Organization	Yes or No	Question 1 Comment

Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.

The SDT agrees and has adjusted the language to allow for multiple Transmission Operators.

> **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless ~~-~~such actions would violate safety, equipment, regulatory, or statutory requirements.

By definition an IROL violation occurs when the IROL limit is exceeded for a duration greater than T_v. Thus, it must be the time duration. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made.

Requirement R9 does not apply to SOLs which are not identified in Requirement R8. No change made.

The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

The subset of SOLs in this requirement was created in response to industry comments. No change made.

Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made.

The SDT agrees.

> **R6**. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated

Organization	Yes or No	Question 1 Comment
communication channels between the affected entities. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Detroit Edison	Negative	The requirement to notify all negatively impacted interconnected NERC registered entities of planned telemetry outages is overly burdensome. Many small generators could technically be impacted, yet not very meaningful impact on a cumulative basis.
Response: The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.		
ACES Power Marketing Member Standards Collaborators	No	We largely agree with the changes but have identified the following specific issues. We disagree with removing Bulk Electric System (BES) from the purpose of the standard. NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Substituting BES for “interconnection” in the purpose statement may solve this issue. While the title contained in the header was changed to “Transmission Operations” the actual title was not changed. They should match. For simplicity, we recommend striking “known or expected to be” from

Organization	Yes or No	Question 1 Comment
		Requirement R3. As it is written now, it is more confusing. First, the TOP, can only notify other TOPs that it knows are affected. Second, the use of "expected" implies that something different is meant than known. If so, what is the intention of the meaning and whose expectation is it: the responsible TOP, the other TOP, the auditor or some other entity? There is a similar issue regarding "known or expected to result in an Adverse Reliability Impact" in Requirement R5. We recommend striking "or expected" for simplicity and to avoid the confusion of whose expectation it is. In Requirement R8, "while not IROLs" should be "while not an IROL". We agree with removing the 30 minute limit in Requirements R9 and R11 and basing the time limit upon the Facility Rating or Stability criteria. In Requirement R10, striking "each" before SOL would improve the clarity of the requirement. In Measurement M1, "nless" should be unless. This may already be correct. The red-lines show "nless" and the clean document shows "unless". What is the intended difference between Transmission Operator Area in Requirement R5 and internal area in Requirement R8? Should they be the same and if not why not?
Southwest Transmission Cooperative, Inc.	Affirmative	We disagree with removing Bulk Electric System (BES) from the purpose of the standard. NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader

Organization	Yes or No	Question 1 Comment
		than the BES, we would like to see BES inserted back into the purpose statement. Substituting BES for "interconnection" in the purpose statement may solve this issue. While the title contained in the header was changed to "Transmission Operations" the actual title was not changed. They should match. For simplicity, we recommend striking "known or expected to be" from Requirement R3. As it is written now, it is more confusing. First, the TOP, can only notify other TOPs that it knows are affected. Second, the use of "expected" implies that something different is meant than known. If so, what is the intention of the meaning and whose expectation is it: the responsible TOP, the other TOP, the auditor or some other entity? There is a similar issue regarding "known or expected to result in an Adverse Reliability Impact" in Requirement R5. We recommend striking "or expected" for simplicity and to avoid the confusion of whose expectation it is. In Requirement R8, "while not IROLs" should be "while not an IROL". We agree with removing the 30 minute limit in Requirements R9 and R11 and basing the time limit upon the Facility Rating or Stability criteria. In Requirement R10, striking "each" before SOL would improve the clarity of the requirement. In Measurement M1, "nless" should be unless. This may already be correct. The red-lines show "nless" and the clean document shows "unless". What is the intended difference between Transmission Operator Area in Requirement R5 and internal area in Requirement R8? Should they be the same and if not why not?
Response: BES: The purpose of the standard is to address reliability needs. Any concerns about BES vs. BPS in standards are		

Organization	Yes or No	Question 1 Comment
better directed toward the Standards Committee. No change made. Title: Conforming change has been made. R3: The SDT sees no additional clarity from the suggested change. No change made. R5: The SDT sees no additional clarity with the suggested change "known or expected to be affected". This language was chosen to cover all situations, including an ongoing event. No change made. R8: The SDT agrees. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. The SDT thanks you for your support on removal of the 30 minute limit. R10: The SDT agrees and made the conforming change. **R10**. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or ~~each~~an SOL identified in Requirement R8, has been exceeded. M1: This has been corrected. In response to this and other comments, Requirement R8 has been edited to match the language in Requirement R5.		
Lincoln Electric System (LES)	No	R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included a provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't

Organization	Yes or No	Question 1 Comment
		identified in R8? R8 is unclear as currently drafted. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation.

Response: R7 and R9: By definition an IROL violation occurs when the IROL limit is exceeded for a duration greater than T_V. Thus, it must be the time duration. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made.

Requirement R9 does not apply to SOLs which are not identified in Requirement R8. No change made.

R8: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R8 and R9: The subset of SOLs in this requirement was created in response to industry comments, resulting in no conflict with the purpose of the standard. No change made.

R10 and R11: Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to

Organization	Yes or No	Question 1 Comment
handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made. R6: The SDT agrees. **R6**. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Progress Energy	No	Progress, while supporting what we believe is the overall intent of this Standard revision, cannot support an affirmative vote on TOP-001-2. Progress appreciates the efforts of the SDT and offers the following suggestions: In R8 it remains unclear what is meant by the phrase "supporting its internal area reliability." Clarity and unambiguous language is needed here so that entities can clearly understand and comply with the requirement. Progress understands from reading the most current "Consideration of Comments" that the Standard Drafting Team left this phrase intentionally undefined; however, the inclusion of this phrase means that in an audit scenario there could be a disagreement about what "supporting its internal area reliability" means. This has the potential to negatively impact the compliance position of the Transmission Operator. In R9 it is unclear what is meant by a "continuous duration that would cause a violation..." Some entities may have facility ratings that are time based, while other entities take the position that the exceedance of a facility rating for any amount of time means an SOL violation. A suggested change in wording would be to simplify the requirement to read "Each Transmission Operator shall not operate outside any SOL indentified in Requirement R8 that would cause a violation of the Facility Rating or Stability criteria upon

Organization	Yes or No	Question 1 Comment
		which it is based." Progress suggests changing R10 to read "Each Transmission Operator shall inform its Reliability Coordinator of the mitigation actions it has taken or directed to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded." The current draft language implies that the TOP must only inform the RC of "...its actions..." Progress suggests switching the order of the current R10 and R11; from reading the most current "Consideration of Comments" it seems that the actions required in R8-R11 are intended to be sequential. Progress suggests that switching the order of the current R10 and R11 would make it easier for a reader to understand that these are intended to be sequential actions.
Response: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. Ratings include the element of time. Continuous duration' has its common meaning. The phrase "for a continuous duration" was added in response to industry comments. No change made. The SDT believes the requirement mandates that the Transmission Operator inform of any actions which would include directions to others and sees no additional clarity with the suggested change. No change made. This is not a procedure and the order of the requirements doesn't matter. There is no additional clarity provided by the suggested change. No change made.		
LG&E and KU Serivces	No	LG&E and KU Services believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This

Organization	Yes or No	Question 1 Comment
		is a Reliability Directive." to avoid any possibility of confusion.
Response: The definition does not include the regulated action. Requirement R1 states that it must be identified. The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.		
City Water Light and Power (CWLP) - Springfeild – IL	No	R8 requirement to identify "...SOLs which...have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis" is vague and difficult to measure. "Internal area reliability" could conceivable include all SOLs CWLP echoes SERC Operating Committee comments submitted separately:" We suggest that the definition of Reliability Directive should be modified as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or "an event that results in Bulk Electric System instability or Cascading". We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition."
Response: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. If the Transmission Operator believes it needs to include all of its SOLs, the requirements do not preclude them from doing so. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.		
United Illuminating Company	No	R3 phrase "known or expected to be affected by each actual and anticipated

Organization	Yes or No	Question 1 Comment
		Emergency based on its assessment of its Operational Planning Analysis" is confusing. Glossary defines emergency as Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. Glossary defines Operation Planning analysis as An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints(transmission facility outages, generator outages, equipment limitations, etc.).I do not see the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to effected by an anticipated Emergency. Those TOP's known to be effected are part of the group expected to be effected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. Along the thought the Time Horizon in the Requirement is Operations Planning. I suggest rephrasing this requirement as:R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Comment for R8. It seems that double jeopardy is introduced with TOP-001 R8 and FAC-011 R5.2. Fac-011 R 5.2 states The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area; while TOP-001 R8 states R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal

Organization	Yes or No	Question 1 Comment
		area reliability based on its assessment of its Operational Planning Analysis.
Response: The SDT sees no additional clarity with the suggested change. No change made. The subset of SOLs in this requirement requires special handling (an incremental requirement to FAC-014-2, Requirement R5.2), thus, this requirement does not introduce double jeopardy. While FAC-014-2, Requirement R5.2 requires the Transmission Operator to provide all of the SOLs it developed to the Reliability Coordinator, proposed TOP-001-2, Requirement R8 requires the Transmission Operator to further sub-divide those SOLs into those that require special handling in this standard. No change made.		
California Independent System Operator	No	R6 requires Balancing Authorities and Transmission Operators to notify “negatively impacted interconnected NERC registered entities” of planned outages. This term is not specific enough to narrow down who must be notified. For instance, with this open-ended wording it could be construed that BAs would have to notify LSEs and DPs in their areas which would be an onerous task. We would recommend staying with “negatively-affected BAs and TOPs.” The wording in R9 is confusing and is not specific enough to ensure compliance. In particular the requirement prohibits operation outside any SOL “for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.” However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. In addition, under R9 and M9, how will the word “continuous” be defined or measured? This is extremely important to understand because the VSL table states the following as Severe for R9: “The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria.” It seems that the effective date should be set much sooner than 24 months following approval since there are basically no new requirements associated

Organization	Yes or No	Question 1 Comment
		with this standard. Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Response: R6: The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made. R9: 'Continuous duration' has its common meaning. No change made. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
We Energies	No	R3's wording is incomplete. It requires informing and states who must be informed but does not state what must be told. The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP's BA(s) of an Emergency. Should also include the BA informing its RC and TOP(s) R4 It is not clear what emergency assistance a TOP can provide? Most actions would involve moving a generator or shedding load, the few items a TOP can do independently like returning a line from outage, or switching reactive devices should be done as a matter of course. R5 The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP's BA(s) of an operation resulting in an Adverse Reliability Impact. Should also include the BA informing it's RC and TOP(s) R6 is overly broad. Every entity in an interconnect can be negatively impacted somehow. The requirement should be focused on the operational

Organization	Yes or No	Question 1 Comment
		entities of the TOP, BA and RC. These are the entities that specify the data that must be made available see IRO-010, proposed TOP-003 from others. Individual asset owners provide data to the operators and when the operators plan an outage they should let the other affected TOP, BA and RC know its to happen. R8: change “have” to “has”. The associated measures should be updated to reflect the above. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.

Response: R3: The SDT does not see that the suggested change improves clarity. The requirement indicates that the recipients must be told about the effect on them of an actual or anticipated emergency. No change made.

R4: The Transmission Operator has actions that it may take or direct such as switching, bringing on capacitor banks, delaying maintenance, etc. All of these are possible emergency assistance actions.

R5: Requirement R5 is for transmission so the Balancing Authority can't be included (Balancing Authority’s have no transmission information). No change made. Approved EOP-002-3, Requirement R3 covers the situation for a Balancing Authority needing to inform others of impacts. No change made.

R6: The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.

R8: The SDT agrees.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

Measures: Conforming changes were made to measures.

Organization	Yes or No	Question 1 Comment
Data Retention: The SDT agrees and has deleted the compliance phrasing.		
American Transmission Company, LLC	No	o If the definition of "Reliability Directive" remains, the Definitions of Terms Used in the Standard should note that there is in fact a new or revised definition. ATC agrees with the definition. o Requirement 4 - This should have a control by the Reliability Coordinator to ensure that a Transmission Operator in distress has, in fact, implemented their "comparable emergency procedures". o Requirement 5 - ATC does not agree with removing the BA from this requirement since they make note that it will be addressed in another, "proposed" requirement as stated in the mapping document. o Requirement 7 - Real-Time EMS representation of IROL Tv, will require an unidentifiable amount of resources. o Requirement 9 - SOL's should have a time requirement. Also, they should not be raised to the level of IROL's as may be insinuated by this requirement if they are discretionary, as noted in Requirement 8. o Requirement 11 - If this requirement entails the issuing of a "Reliability Directive", it should be stated as such.
Response: Reliability Directive: This standard does identify this definition as a new definition that is being developed by Project 2006-06. It also mentions that the RTO SDT is coordinating with that project. R4: In the context of mandatory standards, no Reliability Coordinator control is needed. No change made. R5: The Balancing Authority did not appear in Requirement R5 so the SDT does not understand the comment. No change made. R7: It is common practice in the industry to have ratings with both magnitude and duration. The SDT understands that there are relatively few IROLs, and does not expect a significant burden on the Transmission Operator to be able to comply with this requirement. Also, the requirement does not dictate the technological tools used in assuring compliance. No change made. R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. Some SOLs are based		

Organization	Yes or No	Question 1 Comment
off of Facility Ratings and, thus, include the time dimension. It is to the Transmission Operator's discretion to select the appropriate SOLs in Requirement R8 that it feels need to be treated like this. No change made. R11: This requirement does not have to specify how an instruction is issued. No change made.		
Omaha Public Power District	No	OPPD is concerned with Requirements (R8 and R9) related to System Operating Limits (SOLs). We would like to ask the SDT to clarify what the word "continuous duration" means in terms of timing. We understand the "continuous duration" is based on Facility Rating or Stability criteria, however, without any defined time frame, the term "duration" would be subject to variety of interpretations. OPPD supports a time window to allow TOP to return from SOL similar to IROL Tv.
Response: SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. 'Continuous duration' has its common meaning. It is to the Transmission Operator's discretion to select the appropriate SOLs in Requirement R8 that it feels need to be treated like this. No change made.		
Manitoba Hydro	No	R1 - Manitoba Hydro suggests that the first instance of 'identified' in R1 be removed as it is redundant given that R1 already specifies that the Reliability Directive is 'identified as such'. As drafted, the standard suggests that there is a difference between an 'identified Reliability Directive' and a 'Reliability Directive'. Data Retention (1.3) – The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified logs, recordings and emails, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. This comment applies to TOP-001-2, TOP-002-3, and TOP-003-1.

Organization	Yes or No	Question 1 Comment
Response: The SDT agrees and has deleted the first instance of 'identified'. **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless -such actions would violate safety, equipment, regulatory, or statutory requirements. Data Retention: The language in the 1st paragraph is boilerplate that is inserted in all standards. Compliance language is not under control of SDT. No change made.		
Texas Reliability Entity	No	In R1, the phrase “and identified as such” is redundant and unnecessary in that “identified” already exists within the sentence. Furthermore, the addition of the word “identified” or phrase “identified as such” inserts undue ambiguity and complication, and we are concerned that the “identified” concept will actually provide more opportunities for miscommunications during tense situations. In R1, we are concerned that “Directive” is being proposed with descriptive terms (e.g., “reliability”), and if the descriptive terms are not used explicitly an entity may not be compelled to act accordingly (also may provide leverage for a perceived loophole in compliance activities that could be exploited-“I was unaware it was a {insert descriptive term} Directive”). There should be a time frame associated with requirement R2. Perhaps add “within the timeframe determined for the Directive being issued” to end of sentence. Also, we suggest removing “identified” from requirement R2 (see comments on R1). oThere should be a time frame associated with the communication required by Requirement R5. oR5 should explicitly include IROL, SOL, and Stability Limit violations in the examples since the proposed definition of Adverse Reliability Impact implies

Organization	Yes or No	Question 1 Comment
		instability and Cascading outages. oWe suggest rewriting R5 as follows: "Each Transmission Operator shall inform its Reliability Coordinator and other affected Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas within a timeframe that is sufficient for the RC and affected TOP's to respond to the system condition, unless conditions do not permit such communications. Such operations may include, but are not limited to, Interconnection Reliability Operating Limit (IROL) violations greater than Tv, System Operating Limit (SOL) violations, Stability Limit violations, relay or equipment failures, and changes in generation, Transmission, or Load." In R9, the use of "continuous duration" in the revised language is confusing and should be removed. It would be better to clearly rely on the other standards that relate to identifying IROLs and SOLs (including duration limits), which may have multiple time limits associated with various operating conditions. We note that an SOL may not be based on a single Facility Rating but may actually be a group of Facilities aggregated into a single limit. We suggest saying: "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria, including duration, upon which it is based".

Response: The SDT agrees and has deleted the first instance of 'identified'.

> **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless ~~-~~such actions would violate safety, equipment, regulatory, or statutory requirements.

Some instructions are more important than others. In order to separate these more important instructions from those for routine actions, the descriptive 'adjective' is required so that the receiving entity understands the importance of the instructions. Reliability Directives are of such importance that the actions taken must conform exactly to the instructions as opposed to routine operating instructions which may allow for some discretion. If this isn't made clear during the event, then it is not a Reliability

Organization	Yes or No	Question 1 Comment
Directive. This is not a loophole and is consistent with the recent Board of Trustees adopted interpretation of COM-002-2 that makes clear that directives are intended for emergencies only. No change made. The Reliability Directive in question will include the timeframe for the response if one is needed. No change made. The term 'identified' was included in Requirement R2 in response to industry comments that all Reliability Directives must be identified as such. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. R5: The examples are not types of violations but types of operations. No change made. R9: 'Continuous duration' has its common meaning. No change made.		
New York Independent System Operator	No	Communications must be a well defined, consistent and established process to promote clear and accurate communications between operators for both normal and emergency conditions. This standard could be interpreted as to require an extra phrase during emergencies that would unnecessarily complicate communications. The requirement is reasonable if the identification of a 'Reliability Directive' may be done in a policy or procedure that is communicated to the BA, GOP, DP or LSE as a communication protocol that addresses normal and emergency communications. Otherwise requiring different verbal communication protocols for normal or emergency conditions will add a level of risk currently not observed.
Response: The SDT disagrees that including a simple statement that this is a Reliability Directive complicates communications. In fact, the SDT thinks it improves communications because the recipient understands it must follow the Reliability Directive explicitly. There is nothing in this standard that prevents an entity from adopting formal communication protocols to always identify directives as such to ensure consistent and uniform communications. No change made.		

Organization	Yes or No	Question 1 Comment
Xcel Energy	No	R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity informs its Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. We would like to see additional clarification to clarify “equipment”, suggest using “equipment limitation” or “equipment rating” R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. This requirement should be modified so as not to place the burden on the assisting entity to demonstrate that the requesting entity has implemented “comparable emergency procedures”. Suggest the following language: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment ratings, regulatory, or statutory requirements. R5. Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. This requirement appears to duplicate PRC-001-1 R2 and R5. It is assumed, but cannot be verified that those requirements will be eliminated in a future approved version of that standard. R9 - We appreciate the drafting team’s efforts. However, we are still concerned that R9 will not allow the Transmission Operator the flexibility to identify the best SOL recovery approach, without incurring a violation of the

Organization	Yes or No	Question 1 Comment
		requirement. Instead, the TOP may be forced to shed load in order to avoid violating the requirement. This is not ideal, especially when the situation could be mitigated successfully with alternative measures. It is not clear if an entity is allowed to use an RC-approved contingency plan to mitigate a situation that would cause a Facility Rating violation (i.e. the Facility Rating is the SOL), without also incurring a violation of R9. To further explain, if an entity foresees exceeding an SOL in its OPA, and obtains approval from the RC on their proposed contingency plan (which includes a Facility Rating violation), will that entity be considered in violation of R9 once the exceedance occurs and the contingency plan is implemented? R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. This requirement should specify a sustained period which establishes when it is considered that the entity has returned below the limit (or some other value so as to not misconstrue momentary recoveries as meeting this requirement).

Response: R1: All terms are descriptors of the word 'requirements' so the SDT believes that your concerns have been met with the existing language. No change made.

R4: Industry comments caused the SDT to insert the 'comparable' language. No change made.

R5: The SDT is proposing to retire PRC-001-1 Requirements R2, R5, and R6. A redline of PRC-001-1 will be posted with these comments.

R9: Ratings include the element of time, that is, ratings are two dimensional, with a magnitude limit and time (duration) limit. ‘Continuous duration' has its common meaning. The flexibility remains within these requirements to have a mitigation plan in place. However, the mitigation plan must avoid causing a ratings violation (avoid exceeding the magnitude limit for greater than T_v), else, it would be a violation of this requirement. No change made.

R10: Requirement R10 is about actions taken by the Transmission Operator and not about relief attained. That is covered in the IRO standards. Therefore, no change is necessary.

Organization	Yes or No	Question 1 Comment
ReliabilityFirst	No	ReliabilityFirst has the following comments for consideration: 1. Definition of Reliability Directive - ReliabilityFirst believes there could be a possible issue with the definition of "Reliability Directive" being developed and approved via another drafting effort (i.e. Project 2006-06). In the hypothetical situation where the TOP-001-2 standard is approved and the definition of "Reliability Directive" is drastically changed through the Project 2006-06 effort, there could possibly be a disconnect between the TOP-001-2 requirements and the "Reliability Directive" definition. Also, ReliabilityFirst recommends adding a parenthetical "(e.g. IROL or SOL violations)" to the end of the definition for further clarity. 2. R2 - There is no time qualifier specified in R2 dealing with the timeframe in which the applicable entity has to inform its Transmission Operator of its inability to perform an identified Reliability Directive. ReliabilityFirst recommends the SDT consider adding language to include a timeframe for the entity to inform the Transmission Operator (such as one hour). Absent any specified timeframe, an applicable entity could hypothetically inform its Transmission Operator of its inability to perform an identified Reliability Directive 30 days after the Reliability Directive was issued, and still be compliant based on the current words of the requirement. 3. R4 - The term "emergency" is used within this requirement and ReliabilityFirst seeks clarification on whether this is referring to the NERC definition of "Emergency" (as defined in the NERC Glossary of terms)? If so, this term should be capitalized. 4. R5 - The last sentence in R5 is not really a requirement, but rather a measure on how to comply with the requirement. ReliabilityFirst recommends deleting the last sentence of R5 and incorporating it into the corresponding Measure. 5. R6 - ReliabilityFirst recommends removing the term "negatively impacted

Organization	Yes or No	Question 1 Comment
		interconnected NERC registered entities" and replace it with the associated functional entities (e.g. Balancing Authority, Generator Operator, etc.). 6. R8 - ReliabilityFirst recommends removing the term "while not IROL's" from R8. SOL is a NERC defined term and the extra qualifier is not needed. 7. R10 and R11 - ReliabilityFirst recommends swapping the order of R10 and R11. From a chronological standpoint, the Transmission Operator will "act or direct others to act, to mitigate..." (R11) prior to "informing its Reliability Coordinator of its actions" (R10). 8. Data retention - ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the last sentence states "the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.

Response: Reliability Directive: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team also. This comment will be passed to that team for consideration.

The Reliability Directive in question will include the timeframe for the response if one is needed. No change made.

The NERC defined term "Emergency" was not the intent of this requirement. In this requirement, 'emergency' means actions taken quickly in response to an immediate need. No change made.

The last sentence in Requirement R5 is intended to provide guidance on the kinds of operations that should be communicated and is better kept in the requirement. No change made.

If the entities were listed, the list would include every NERC functional entity that has telemetry. This change would not improve

Organization	Yes or No	Question 1 Comment
reliability. No change made. IROLs are a subset of SOLs as defined by NERC. The requirement concerns a different subset of SOLs. No change made. This is not a procedure and the order of the requirements doesn't matter. There is no additional clarity provided by the suggested change. No change made. Data Retention: The language in the 1st paragraph is boilerplate that is inserted in all standards. The compliance language is not under control of SDT. No change made.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agecny supports comments submitted by the SERC OC Standards Review Group and the ISO/RTO Standards Review Committee concerning the need to address the “Reliability Directive” definition in concert with COM-002-3.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.		
Duke Energy	No	While the drafting team has made several improvements to this standard, we believe these additional changes are needed: o The definition of Reliability Directive includes the defined term “Adverse Reliability Impact”, which should be replaced by the actual wording of latest BOT-approved definition of “Adverse Reliability Impact”, since it has not yet been approved by FERC. If the SDT decides not to replace Adverse Reliability Impacts with the actual wording of the latest BOT-approved definition, then the SDT should delete the “s” from “Impacts”. o R8 - We believe that the phrase “supporting its internal area reliability” should be further clarified in some way. The inclusion of the undefined concept of “supporting internal area reliability” creates undue compliance risk, since auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”. The drafting team could examine the disturbance reporting criteria in EOP-004-1

Organization	Yes or No	Question 1 Comment
		Attachment 1 to help develop a reasonable threshold for reporting SOLs to the Reliability Coordinator. o R8 - Consistent with R3, the Time horizon for R8 should only be Operations Planning. o R9 - The change that has been made to R9 could be interpreted to result in a violation if a facility rating is exceeded for any amount of time at all. Similar to an IROL's Tv, SOLs identified under R8 should have an identified time period (such as 30 minutes) for mitigation without a violation. A change to R9 should be coupled with development of a reporting threshold for R8 as discussed above. o M1 - typo, left the "u" off the word "unless". o Measures for R8 and R9 should be changed consistent with our suggested revisions to the requirements.

Response: "Reliability Directive" is under the auspices of the RC SDT (Project 2006-06). This has been passed on to that team.

R8: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

> **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R8: The SDT agrees and has changed the Time Horizon to Operations Planning.

R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made.

M1: This has been corrected.

Organization	Yes or No	Question 1 Comment
M8 and M9: Conforming changes were made to Measure M8. No changes were made to Requirement R9.		
South Carolina Electric and Gas	No	Please provide clarity on the phrase "support its internal area reliability" in R8.
Response: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Oklahoma Gas and Electric	No	A. In the draft TOP-001-2 standard, R1 and R2 both address complying with Reliability Directives. OG+E suggests these two requirements be combined into one requirement using similar language found in other standards that contain the same Reliablity Directive requirement, such as IRO-001-1.1 R8 and the previous version of this standard for consistency purposes. B. Mitigation of IROLs is ultimately the responsibility of the RC. TOPs act under the direction of the RC when mitigating IROLs. TOP-001-2 R11 should clarify by adding the following to the beginning of the requirement. "Under the direction of the RC, each TOP shall act or direct others to act...". C. Please clarify the meaning of "internal area realiability" in R8. D. In R9, "continuous duration" warrants additional clarification. Is this 5, 10, 30, 60 minutes of operating outside the SOL? Or only continuous operation outside of SOL that results in ultimately exceeding the Facility Rating?

Organization	Yes or No	Question 1 Comment
Response: R1 and R2: The SDT sees no additional clarity with the suggested change. No change made. R11: Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made. R8: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. 'Continuous duration' has its common meaning. No change made.		
American Electric Power	No	R7, R9, R10, & R11 - It needs to be clarified whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader. Taken together, the combination of R7 and R9 appears redundant with R11, as meeting the objective of R7 and R9 would imply taking the proper mitigating measures. AEP suggests either eliminating both R7 and R9 or eliminating only R11. If r7 and R9 were to be eliminated, the references to magnitude and duration should be removed from R11, as the associated measure is binary

Organization	Yes or No	Question 1 Comment
		in respect to the limit, i.e., either the limit has been exceeded or it has not. It would be premature for AEP to support the associated VSLs and VRFs given the objections stated above.
Response: R7, R9, R10, and R11: The SDT agrees for SOLs, however, it must be noted that IROLs have been defined as both pre-contingent and post-contingent. The exact definition of the IROL must be honored. No change made. R7, R9 and R11: These requirements are the core Transmission Operator requirements that assure continued reliable operation of the BES. If the Transmission Operator acts or directs others to act to mitigate, as in Requirement R11, but the facility remains in violation of Requirements R7 or R9, then the Transmission Operator is compliant with Requirement R11 and noncompliant with either Requirements R7 or R9, as dictated by the exact circumstances. If the Transmission Operator fails to act or fails to direct others to act, as in Requirement R11, then it is noncompliant with both Requirement R11 and either Requirement R7 or R9, as dictated by the exact circumstances. This is not double jeopardy. No change made.		
PPL Electric Utilities	No	We believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
PPL EnergyPlus LLC	Affirmative	We believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
Response: The definition does not include the regulated action. Requirement R1 handles the action. Compliance is measured against requirements, not definitions. The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration. No change made.		
Ameren	No	R2. When is “shall inform” to occur; timely, promptly, ... It would be injurious to BES reliability for the TOP to get such information, say 15 minutes or half-hour later as many other things are likely to be put in place on the assumption the directive is “ok”. R3. The wording is incorrect it implies the TOP will notify the RC and its

Organization	Yes or No	Question 1 Comment
		TOP's. The word other may be missing. But even with other the question it begs which other TOP's? It could be argued that the RC only needs to know Emergencies that are both actual and anticipated. They would want to know about them whether they are actual or anticipated. This direction here is not clear; it may be helpful to use two sentences to address and clarify the issues of this requirement. R4. What is meant by emergency assistance is not clear; clarify and provide examples. Is it emergency energy? Is it emergency food? Is it emergency crews? This ambiguity is a compliance nightmare as you have to prove you have everything covered that could loosely be interpreted as emergency assistance. If the SDT has an idea what they are expecting, it should be listed. If they don't have an idea of what constitutes emergency assistance, then we recommend removing it from the Requirement. R5. The Requirement should be re-written to say "Each TOP shall inform only if it adversely affects others its RC and other TOP's (Which other TOP's? This direction here is not clear; clarify) of its operations known or expected to result in an Adverse Reliability Impact ..." R6. What is meant by negatively impacting is not clear; clarify and provide examples. For example, using the words as listed, economic impact might be a consideration. The Standard should not be setting up a condition where TOPs tell GO/GOPs that they might suffer economic harm as a result of one of the communication channels being down. As currently worded this might lead to a civil issue instead of a BES reliability issue. R8. There are SOLs that are developed in real-time (as evidenced by the multi-time-horizon assigned). It might be possible for such an SOL to develop and have to be resolved for local area reliability only, before the RC could be notified. This Requirement should insert the word planned before SOL. Alternatively, insert where time permits in place of real-time.

Organization	Yes or No	Question 1 Comment
		R9. What is meant by continuous duration is not clear; clarify. Is it 5 minutes, 15 minutes, an hour, a day? Anything more than 5 minutes is likely to be in the thermal time-constant period where rating could be affected. We feel that the real intent of this requirement is that TOPs resolve SOLs. It is not so much how long, as it is that they are not purposely delaying the resolution. The Requirement should be re-written to say "The TOP's will resolve as soon as possible anys SOL...... with no intentional time delay..." R10. The Requirement as written should be prefaced with "when time permits, each Transmission Operator....." The idea of time permitting is alluded to in R5, "unless conditions do not permit such communications".

Response: R2: The Reliability Directive in question will include the timeframe for the response if one is needed. No change made.

R3: The word 'other' is not required. The language following Transmission Operator confines the set of which Transmission Operators. No change made.

R4: The NERC defined term "Emergency" was not the intent of this requirement. In this requirement, 'emergency' means actions taken quickly in response to an immediate need. No change made.

R5: The requirement has the Transmission Operator with the issue limited to notifying those "other Transmission Operators" whose Transmission Operator Areas are expected to have an Adverse Reliability Impact. No change made.

R6: NERC requirements are concerned only with reliability of the BES, not economic harm. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.

R8: The key phrase in this requirement is 'based on its assessment'. No change made.

R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. 'Continuous duration' has its common meaning. No change made.

Organization	Yes or No	Question 1 Comment
R10: Requirement R5 allows for the possibility of a suddenly developing condition. Requirement R10 is concerned with the reporting of actions after they occur. No change made.		
Tacoma Public Utilities	Affirmative	We would like to request that specific definitions are included for the individual time horizons. We suggest the following potential definitions: 1. Same Day Operations - Routine actions required within the time frame of a day, but not real-time. 2. Real-time Operations - Actions required within one hour or less to preserve the reliability of the bulk electric system. 3. Operations Assessment - Follow-up evaluations and reporting of real-time operations.
Response: These are defined in the NERC SDT Guidelines. No change made.		
NIPSCO	Yes	In R8 consider changing "internal area" to "Transmission Operator Area" In R9 consider clarifying "continuous duration", what is that?
Response: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. 'Continuous duration' has its common meaning. No change made.		
Georgia System Operations	Yes	GSOC agrees in general but feels that some clarity should be provided. The purpose of the language "each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area

Organization	Yes or No	Question 1 Comment
		reliability based on its assessment of its Operational Planning Analysis" (OPA) is not clear. Is the intent to clarify the meaning of SOL? If so the definition in the glossary should be updated to clarify the meaning and the clarification should be removed whenever used in TOP-001, 002, or 003. Is the intent to limit which SOLs are being referred to? Not each SOL but each SOL which have been identified as supporting the internal area reliability based on the assessment of its OPA. Could this language be deleted and still convey what is required?
Response: The SDT disagrees that the phrase is not clear. It is identifying SOLs that the Transmission Operator feels are important enough to request that they be monitored similar to an IROL. This could occur for any number of reasons. No change made.		
Associated Electric Cooperative, Inc.	Yes	R3 Guidance Add: A Guidance Section for Requirement R3 clarifying “anticipated Emergency” - AECI believes the SDT should draft guidelines as to what “anticipated Emergency” means within this requirement. That guidance should also caution against dumping information (data-overload) upon neighboring parties, for trivial impacts to their system. Rationale: In earnest to avoid non-compliance with R3, entities could blast their neighbors with all changes, regardless of impact, and then the purpose of this requirement will be lost.) R6 Requirement wording Change: “negatively impacted” To: “known negatively impacted” Rationale: While 1st hand affected parties are likely known, secondarily affected parties might pose a compliance problem. R8 Guidance Add: An R8 Guidance section Rationale: AECI’s understanding is that our providing our RC with AECI’s most-limited-element equipment seasonal operating limits and short-term limits, where applicable, meets this requirement. If we are wrong, then additional guidance is definitely necessary.
Response: The requirement is limited by the fact that actions are based on your assessment of the Operational Planning		

Organization	Yes or No	Question 1 Comment
Assessment. No change made. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. The Transmission Operator must comply with FAC standards for proper definition of SOLs. An SDT cannot give compliance advice.		
Dairyland Power Cooperative	Yes	Concern re R5. The determination of when an operating condition could be "expected to result in an Adverse Reliability Impact" would be difficult and ambiguous.
Response: The Transmission Operator is in the best position to know if other areas may suffer an Adverse Reliability Impact. The examples cited in the requirement: "Such operations may include relay or equipment failures and changes in generation, Transmission, or Load" are intended to give guidance. No change made.		
NV Energy	Yes	Yes, however, there are a few points to note: Part A, Section 1 continues to title this standard as "Coordination of Transmission Operations, while the header of the Standard was changed to simply "Transmission Operations". The requirements R6 and R8 appear to be outside the realm of real-time operations, R6 dealing with planned outages of telemetry, comm, and control equip, and R8 dealing with communication of SOL's or other limits. It is confusing to mix in Operations Planning type requirements in a standard that otherwise deals with real-time grid operations. Suggest relocating these two to the Operations Planning Standard, TOP-002-3.
Response: Title: Conforming change has been made. R6 and R8: Telemetry outages may be planned for the same day or in the next hour. SOLs may be affected in similar timeframes (new topology forcing a readjustment of the system, for instance). No change made.		

Organization	Yes or No	Question 1 Comment
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	From the GO/GOP perspective, Ingleside Cogeneration LP believes that the SDT has captured the appropriate circumstances for when a Reliability Directive is issued and identified - and the circumstances under which it may be not be possible to accommodate one.
US Bureau of Reclamation	Yes	
Westar Energy	Yes	
FirstEnergy	Yes	
Dominion	Yes	
PacifiCorp	Yes	
Western Area Power Administration	Yes	
FMPP	Yes	
Luminant Energy Company, LLC	Yes	
Independent Electricity System Operator	Yes	
Response: Thank you for your support.		

2. **The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: There were four common concerns expressed in the comments.

First, the "rationale box" for Requirement R1 was eliminated. The SDT agreed that the rationale offered was inappropriately addressing more of a compliance issue than explaining the background reasoning.

Second, commenters questioned the use of Facility Ratings and Stability Limits in Requirement R1 rather than the use of the terms Interconnection Reliability Operating Limit and System Operating Limit. The SDT prepared responses to clarify the reasoning for the use of Facility Ratings and Stability Limits, but did not change the wording of the requirement.

Third, the commenters questioned the use of the phrase "internal area reliability" in Requirement R2. The SDT revised Requirement R2 to change the phrase from "internal area reliability" to "reliability internal to its Transmission Operator Area" to clarify that the requirement is related to a Transmission Operator Area, which is a defined term, and that it is a reliability concern within that area, not one that concerns other areas nor does it rise to the level of adversely affecting the reliability of a wider area ~~or~~ of the Bulk Electric System.

Fourth, some commenters expressed concern about Requirement R3 and the notifications of entities which are identified as having roles in operating plans developed by the Transmission Operator in Requirement R2. The concern was related to whether the notifications may conflict with confidentiality requirements. The SDT explained that the notifications are simply to alert the entities that they have been identified as having roles in the operating plans to address reliability issues, but that such notifications do not have to include specifics about what the plan is to address. The entity may know that it may be called upon to perform its role of switching, changing of generator output, or other similar actions, but no specific information would be issued that may result in the unintended consequence of giving any entity "market power" or other competitive advantage.

The SDT has made no substantive changes to the requirements of TOP-002-3. However, Requirement R2 was clarified as follows:

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

Organization	Yes or No	Question 2 Comment
Muscatine Power & Water	Negative	First and foremost is the Requirement in TOP-002-3 for having a process for performing an "Operational Planning Analysis." That term, "Operational Planning Analysis," does not have a FERC-approved definition. The definition floating around at NERC implies some sort of simulation (with or without a tool) being perform next-day to determine exceedence of facility ratings or stability limits.
Response: The definition of Operational Planning Analysis was approved by FERC in March 2011.		
New Brunswick Power Transmission Corporation	Negative	R3: The TOP may not have authority over external registered entities. The TOP should only have to notify and coordinate with those external entities that have the necessary authority.
Response: Requirement R3 deals with operations planning, thus the notification would be to convey information—not an instruction to implement. The hierarchy of authority is known by the Transmission Operator and other registered entities. This is known even if they are members of differing market structures, contract arrangements, or other organizational arrangements; thus the Transmission Operator will know the effective path of communications to use. No change made.		
ISO/RTO Standards Review Committee	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase ‘within its TOP Area or for which it has been notified by another TOP under R3’ in R1 immediately following (IROL).
Pepco Holdings Inc	No	PHI supports the comments provided by the ISO/RTO Standards Review Committee.
ISO New England Inc.	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity.

Organization	Yes or No	Question 2 Comment
		Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Constellation Energy	No	CCG, CECD and CPG concur with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
BGE	No	BGE concurs with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Southwest Power Pool Reliability Standards Development Team	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1

Organization	Yes or No	Question 2 Comment
		immediately following (IROL).
Southwest Power Pool, Inc.	Negative	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Nebraska Public Power District	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. We suggest the following language for R1: "Each Transmission Operator shall have an Operational Planning Analysis assessing whether the planned Transmission Operator Area operations for the next day will exceed the area Facility Ratings or Stability Limits during anticipated normal and Contingency (at a minimum N-1 Contingency planning) event conditions." Requiring the TOP to develop a plan to operate within each IROL in R2 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its Transmission Operator Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).

Response: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to

Organization	Yes or No	Question 2 Comment
analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies1identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made. Requirement R2 is the correct reference for the second group of comments, not Requirement R1. The SDT believes it is important for the Transmission Operator to develop a plan to operate within each IROL. Further the Reliability Coordinator must inform the Transmission Operator of all IROLs that impact its Transmission Operator Area or that its area can impact in other areas; and other Transmission Operators must inform them of SOLs that either impact its area or that its area may impact. Similar to the often-discussed "loop flow" concern, each entity must recognize that operations within its area may impact SOLs in another area and vice		

Organization	Yes or No	Question 2 Comment
versa.		
United Illuminating Company	No	The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, UI suggests the requirement should either state the requirement for a process to conduct an Operational planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement.R1. The Transmission operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. R2: uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-011 R5. SOL's that affect a TOP internal area would also affect the RC area.
Northeast Power Coordinating Council	No	The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, suggest that the requirement should either state the requirement for a process to conduct an Operational Planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement.R1. The Transmission Operator shall CONDUCT an Operational Planning Analysis for the next day’s planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. Requirement R2 uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-014 R5. SOL’s that affect a TOP

Organization	Yes or No	Question 2 Comment
		internal area would also affect the RC area. The Drafting Team needs to define the term "internal area reliability" in order to improve the clarity of the standard (see Question 1 comments regarding TOP-001 Requirement R8). Regarding Requirement R3, would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall?
Response: R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate and, thus, still applies. R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. R3: When providing the notification, no confidential information must be provided, only that the entity has a role to play in an operating plan that the Transmission Operator has developed to address system constraints. No other regulations may be violated in the issuance of the notifications, but the Generator Owner, Generator Operator, or Balancing Authority would know that they would be asked to change something in their generation operations as a part of their role(s).		
Southwest Power Pool Regional Entity	No	See item number 5 for comments.
Response: See the response to Q5.		
Bonneville Power Administration	No	Given the potential uncertainty regarding how many day ahead studies may be required, BPA suggests adding more clarity to the standard TOP-002-3. BPA recognizes that various regions experience peak operations at different times of the day, anticipated generation patterns shift over the course of the day, and

Organization	Yes or No	Question 2 Comment
		transmission facilities come in and out of service for planned work at various times throughout the day. Hence, due to these multiple shifts in forecast system conditions, it is unclear whether more than one study is required to meet the requirements of this standard.
Response: The requirement states "what" must be done, not "how" it is to be done. There are many tools (please note that use of tools is not required) and the various processes and/or tools may differ with a resulting different number of "studies" required. The Operational Planning Analysis is to address "expected system conditions", such as load forecasts, generator outputs, and system constraints. For those larger, more complex systems, the SDT expects the process may be complex. However, for smaller entities which may have a very constant load characteristic and a very robust transmission system, one analysis may suffice for a very broad range of different "expected system conditions". No change made.		
Imperial Irrigation District (IID)	No	R1 - This requirement requires the Transmission Operator to have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions (Comment) - Recommendation that the requirement language be changed to "Each TOP shall perform the required Operational Planning Analysis for Next-Day Operations to assess if the Next-Day Operations Plan will exceed any of its Facility and/or stability limits under normal or emergency conditions". R2 - This requirement requires the Transmission Operator to develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 (Comment) Recommend that the language be revised for clarity to state the following; "The TOP shall develop a plan to operate within established IROL and SOLs according to the Operation Planning Analysis performed for its Next-Day Operation in Requirement 1. R3 - This requirement requires the TOP to notify all NERC registered entities

Organization	Yes or No	Question 2 Comment
		identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) (Comment) - Recommend revising the language in the requirement to state the following; "The TOP shall notify all affected NERC Registered entities of possible impacts identified in its Operational Planning Analysis for its Next-Day Operations in Requirement 1. M2 - The measurement requires the TOP to have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement (Comment) - Revise the Measurement to state the following; "The TOP shall have evidence that it developed a plan to operate within established IROL or SOLs supporting its internal reliability area as a result of its Operational Planning Analysis performed". M3 - Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records. (Comment) - Revise the measurement to sate the following; "The TOP shall provide evidence that it notified affected NERC Registered Entities as being impacted in the Operational Planning Analysis related to its Next-Day plan. Such evidence shall include but not be limited to dated E-Mails, Operator Logs, or Voice Recordings. Data Retention - Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer. The Compliance Enforcement Authority shall

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<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>keep the last audit records and all requested and submitted subsequent audit records. (Comment): The time frames appear to be pretty specific for the data retention. However when will the entity know that it has to save the evidence farther back than the set time frame. Would it not be better to have the Data Retention language require the entity to save all evidence back 12 months and to save any evidence related to a system disturbance/event?</td></tr>
<tr><td colspan="3">Response: R1: The requirement is to assess the Operational Planning Analysis (OPA). An entity may do this by performing a new OPA each day, or even more often, but it is not required to do so. The SDT can postulate that the varying results of the assessment(s) may indicate the need for a new analysis, or may indicate that the existing analysis is still appropriate. No change made.

R2: See above response for R1. No change made.

R3: The SDT requirement to notify entities of their role(s) in the operating plans goes beyond just informing them of system impacts. The role(s) will notify the entity that they will have actions to take when the Transmission Operator must implement an operating plan to address system constraint(s). No change made.

The SDT made no changes to Measures M2 and M3 because the requirements were not changed.

Data Retention: The language indicates that the entity will be asked by its Compliance Enforcement Authority (or directed) to save the evidence father back than the set timeframe. No change made.</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>The words “develop a plan” in R2 are too broad. Recommend the requirement be modified to include, “within its TOP area” as in R1.

Also the use of “Contingency event conditions” is not clear in requirement R1. Recommend specifying n-1 as the contingency scope.</td></tr>
<tr><td colspan="3">Response: The SDT believes it is important for the Transmission Operator to develop a plan to operate within each IROL. Further the Reliability Coordinator must inform the Transmission Operator of all IROLs that impact its Transmission Operator Area or that its area can impact in other areas; and other Transmission Operators must inform them of SOLs that either impact its area or that its area may impact. Similar to the often-discussed “loop flow” concern, each entity must recognize that operations within its area may impact SOLs in another area and vice versa. No change made.</td></tr>
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Organization	Yes or No	Question 2 Comment
The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will		

Organization	Yes or No	Question 2 Comment
allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.		
SERC OC Standards Review Group	No	Why did the Drafting Team use the terms "Facility Ratings" and "Stability Limits" in Requirement 1 rather than SOLs and IROLs as used in subsequent Requirements? We suggest the Drafting Team further clarify or define the term "supporting internal area reliability" as an aid in demonstrating compliance and how this requirement (R2) enhances reliability.
Response: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate		

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R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.

R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault.

R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.”

TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.

R2: The SDT has revised the language. This requirement enhances reliability by clarifying that a Transmission Operator may identify certain SOLs as important, although they don’t rise to the level of an IROL, but support reliability internal to the Transmission Operator Area. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.</td></tr>
<tr><td>US Army Corps of Engineers</td><td>No</td><td>Issue: The SDT uses a non FERC approved term of Operational Planning Analysis, This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval.

Issue: R2: statement its internal area reliability Should be clarified to state: R2: Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		Transmission Operators area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: statement its internal area reliability could be clarified to state: has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis
MRO-NSRF	No	Issue: The SDT uses a non FERC approved term of “Operational Planning Analysis”, This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval. Issue: R2: statement “...its internal area reliability...” Should be clarified to state: R2: Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: statement “...its internal area reliability...” could be clarified to state:”...has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis...”

Response: The definition of Operational Planning Analysis was approved by FERC in March 2011.

R2: The SDT has revised the language to change “internal area reliability”.

> **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

M2: The SDT revised Measure M2 to correspond to the changes in Requirement R2.

Organization	Yes or No	Question 2 Comment
ACES Power Marketing	No	We largely agree with the changes but have identified the following specific

Organization	Yes or No	Question 2 Comment
Member Standards Collaborators		issues.We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted into the purpose statement. For Requirement R1, it is not clear why focus is on Facility Ratings and Stability Limits rather than SOLs. We suggest using the term SOL instead.
Southwest Transmission Cooperative, Inc.	Affirmative	We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted into the purpose statement. For Requirement R1, it is not clear why focus is on Facility Ratings and Stability Limits rather than SOLs. We suggest using the term SOL instead.
Response: The SDT has been given SDT Guidelines that state that all requirements are written for the BES. No change made. R1: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by		

Organization	Yes or No	Question 2 Comment
the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies1identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.		

Organization	Yes or No	Question 2 Comment
Georgia System Operations	No	GSOC feels that some clarity should be provided. In R1, the rationale confuses things. It states things that are not in the requirement and goes beyond the requirement. If something is intended by the language of R1 other what is stated, then that intent should be clearer in the requirement. For example if a process is required, then state so in the requiremnt. It should not be in a rationale. Also, the comment in the rationale about being able to complete the analysis even if tools are not available is inappropriate in this standard since the situation is covered in EOP-008-1. Remove the rationale and if needed clarify the requirement. R1 states that the TOP should be allowed to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. It does not state that an assessment of this must be done, only that it be allowed.R2 states that the TOP shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which has been identified by the TOP as supporting its internal area reliability, identified as a result of the OPA performed in Requirement R1. R1 does not require that IROLs and SOLs be identified. What if the TOP does not identify if there are any SOLs as a result of the OPA? There are other examples in these standards in which something in the OPA is referred to but is not required to be in the analysis. Better clarity is needed regarding just what the end results of the analysis must be. R3 requires that entities identified in the plan be notified as to their role. Would this be initially and whenever their role changes thereafter? Or just once? Data Retention: It states that if a TOP is found non-compliant, it shall keep information related to the non-compliance until found compliant. It is inappropriate to use the phrase "found compliant." NERC and the REs do not find entities compliant.
Response: R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate		

Organization	Yes or No	Question 2 Comment
and, thus, still applies. No change made. R1: The requirement is for the Transmission Operator to have an Operational Planning Analysis (timeframe of an OPA is built into the definition). If the Transmission Operator chooses to use an existing OPA, then it cannot be confirmed to be appropriate for the next day without performing an assessment of the OPA. If the Transmission Operator chooses to build a new OPA (each day or at a differing recurrent schedule), then the assessment is part of building the OPA in order to make it appropriate to the "expected system conditions". No change made. Identification of SOLs: There is no need to state in these requirements that the IROLs and SOLs be identified, because the Transmission Operator is required to do that by the FAC standards. The end result of an OPA is an evaluation of the "expected system conditions" and the development of operating plans that may be needed to address any identified system constraints. No change made. R3: Entities are to be notified as to their role every time it performs the assessment. Data Retention: The language you question has been provided to the SDT by the NERC Compliance group and is "boiler plate" language that the SDTs are instructed to use. No change made.		
City Water Light and Power (CWLP) - Springfeild - IL	No	R1 should utilize SOL and IROL criteria as opposed to Facility Ratings and Stability Limits criteria for consistency and clarity R1 Rationale language lacks clarity. Poor definition of "process", "tools", and "procedures" could be construed to indicate that a TO must be able to perform analysis internally even when basic non-automated "tools" such as offline power flow software are not available. The intent of "tool" is unclear in general for this instance. If the intent is to capture the use of online automated tools such a Real-Time Contingency Analysis and ensure that offline analysis capabilities are retained, the language should explicitly include "online automated tools" or "real-time automated tools"
Response: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented		

Organization	Yes or No	Question 2 Comment
within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made. R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to		

Organization	Yes or No	Question 2 Comment
assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate and, thus, still applies. No change made.		
We Energies	No	How current should the Operational Planning Analysis be? By definition it can be 12 months ahead. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.
Response: The Transmission Operator must have an OPA (the timeframe is contained within the definition). Data Retention: You are correct. The SDT has made a conforming change to the language to eliminate the phrase.		
American Transmission Company, LLC	No	Requirement 1 - Granted, if the rationale does not mandate "how" an analysis is completed, a better requirement of the "what" should be stated. If this analysis base-case, N-1, is unilateral by the TOP, without iteration with the BA, then should the process be documented?
Response: R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate and, thus, still applies. No change made. In the development of the planned operations for the next day, the Balancing Authority would supply expected generator outputs to the Transmission Operator. The Transmission Operator would determine whether there are any system constraints that would require changes by the Balancing Authority, such as a re-dispatch or other action that may require alterations to the expected generator outputs to be performed by the Balancing Authority. If such things are identified, the Transmission Operator will notify the entities of their role(s) in the operating plans.		
Consolidated Edison Co. of NY, Inc.	No	Comments: In Requirement R2 the Drafting Team needs to define the term "internal area reliability" in order to improve the clarity of the standard. Regarding Requirement R3: Would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>Firewall?

Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.</td></tr>
<tr><td>Orange and Rockland Utilities, Inc.</td><td>No</td><td>Regarding Requirement R3:   Would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall?

Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.</td></tr>
<tr><td colspan="3">Response: R2: The SDT has revised the language.

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability <u>internal to its Transmission Operator Area</u>, identified as a result of the Operational Planning Analysis performed in Requirement R1.

R3: When providing the notification, no confidential information must be provided, only that the entity has a role to play in an operating plan that the Transmission Operator has developed to address system constraints. No other regulations may be violated in the issuance of the notifications, but the Generator Operator, Generator Operator, or Balancing Authority would know that they would be asked to change something in their generation operations as a part of their role(s). The Transmission Operator may direct Balancing Authorities for reliability reasons. Yes, the Reliability Coordinator may also direct the Balancing Authorities, but the Transmission Operator is not precluded from doing so. No change made.</td></tr>
<tr><td>Manitoba Hydro</td><td>No</td><td>R1 - Given that an Operational Planning Analysis is itself an assessment of planned operations (i.e. the definition of Operational Planning Analysis is '<u>An analysis</u> of the expected system conditions for the next day's operation…') it is unnecessary to state that the Operational Planning Analysis must allow an assessment of planned operations. Accordingly, Manitoba Hydro suggests that the phrase that will allow it</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
		to assess…' be replaced with "assessing".
Response: The SDT believes your comments represent a question of semantics. The SDT differentiates between an "analysis" and an "assessment". The difference is that the entity assesses the analysis it has performed to determine that the OPA is still representative of "expected system conditions". That is "what" must be done. The "how" is left up to the entity. The SDT can postulate that the entity may perform a new OPA and, in the process, assess that it is representative of "expected system conditions", or that it may take an existing OPA and assess it to determine that it still is representative. No change made.		
ReliabilityFirst	No	ReliabilityFirst has the following comments for consideration:1. R1 - ReliabilityFirst recommends removing the rationale box from the standard. ReliabilityFirst believes this is not really the rationale for the requirement but rather explains how to measure (show evidence) for the requirement.2. R2 - ReliabilityFirst recommends deleting the following words from the requirement, "which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1". ReliabilityFirst believes this language does not add anything to the requirement. 3. R2 and R3 - R3 requires the Transmission Operator to notify all NERC registered entities identified in the plan(s) but there is no corresponding requirement for the Transmission Operator to identify NERC registered entities in their plans. ReliabilityFirst recommends incorporating this concept into R2. 4. Data retention - ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the last sentence states "the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent

Organization	Yes or No	Question 2 Comment
		paragraphs in the Data Retention section.

Response: R1 rationale box: The SDT agrees and has eliminated the rationale box.

R2: A Transmission Operator may identify certain SOLs as important, although they don't rise to the level of an IROL, but support reliability internal to the Transmission Operator Area. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. However, the SDT has clarified the wording in Requirement R2 due to comments received.

> **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

The SDT believes that to notify the entities, the Transmission Operator must somehow know who the entities are and that stating a requirement to identify them before notifying them would be redundant and would not add to reliability. No change made.

Data Retention: The entity is to do all the shorter retention requirements first and go to the longer retention only if the CEA asks them to do so. No change made.

Organization	Yes or No	Question 2 Comment
Duke Energy	No	o R2 - Consistent with our comment above on TOP-001-2 Requirement R8, the phrase "supporting its internal area reliability" should be further clarified in some way. o M2 typo - the word "plan" has an extra "n".

Response: R2: The SDT has revised the language.

> **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

M2: The typo has been corrected. Please note that the typo is not seen in the "clean" copy.

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	No	Please provide clarity on the phrase "support its internal area reliability" in R2.
Response: R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Oklahoma Gas and Electric	No	Regarding R2, please consider additional clarifying language that each TOP need only develop a plan to operate within IROL and SOL that is applicable to them. Also, clarify what "internal area realibility" means - is this the same as Transmission Operator Area discussed in R1?
Response: The SDT believes it is important for the Transmission Operator to develop a plan to operate within each IROL. Further the Reliability Coordinator must inform the Transmission Operator of all IROLs that impact its Transmission Operator Area or that its area can impact in other areas; and other Transmission Operators must inform them of SOLs that either impact its area or that its area may impact. Similar to the often-discussed “loop flow” concern, each entity must recognize that operations within its area may impact SOLs in another area and vice versa. No change made. R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Westar Energy	No	The stated rationale for R1 raises more concerns than the actual language in R1. How can an entity complete an analysis by procedure? The rationale seems to indicate that an Operational Planning Analysis is possible

Organization	Yes or No	Question 2 Comment
		without tools, please explain. Are anticipated contingency event conditions intended to be N-1 from the planned system configuration?

Response: R1 rationale box: The SDT agrees and has eliminated the rationale box.

The requirement states "what" must be done, not "how" it is to be done. There are many tools (please note that use of tools is not required) and the various processes and/or tools may differ with a resulting different number of "studies" required. The Operational Planning Analysis is to address "expected system conditions", such as load forecasts, generator outputs, and system constraints. For those larger, more complex systems, the SDT expects the process may be complex. However, for smaller entities which may have a very constant load characteristic and a very robust transmission system, one analysis may suffice for a very broad range of different "expected system conditions".

The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them.

FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities.

Organization	Yes or No	Question 2 Comment
FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies1identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.		
Ameren	No	R1. The current language invites a retrospective assessment and a potential compliance issue that if a bad event occurs that was not in the forecast, it may call into question whether the TOP adequately "allowed it to assess" whether operations where within limits. We recommend SDT re-write the requirement: "Each TOP shall have an Operational Planning Analysis that represents projected System conditions for the next day, within its Transmission Operator Area, to identify any projected exceedance of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions." R2. Although the time-horizon assignment provides some cover for real-time SOLs, it would be preferable to add direct clarification to the Requirement as follows. "Each TOP shall develop a next day plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) ..." R3. Taken literally, this Requirement could require TOP notification to a GOP/PSE/LSE that they will be dispatched down in real-time for a projected congestion issue (SOL).

Organization	Yes or No	Question 2 Comment
		This does not make sense and certainly not in organized LMP markets where they would have advance knowledge of market conditions AND FOR THINGS THAT ARE ROUTINE. This is the nexus of the problem for us with this Requirement. The need to notify others of their roles should be restricted to unusual actions in the case of SOL resolution. Arguably this could be true for IROLs too but given the impact perhaps it could remain. We suggest that the Requirement say, “Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) when those actions are unusual or abnormal actions.” OR”Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) for the resolution of IROLs or when those actions are unusual or abnormal actions for the resolution of SOLs.”
Response: The SDT believes the existing language of draft Requirement R1 says what you are requesting. No change made. R2: The FAC standards provide clarity as to the development of Facility Ratings and SOLs. IROLs are a sub-set of SOLs. To provide differing language here would be to provide potential conflict and confusion. No change made. R3: Requirement R3 deals with operations planning; thus the notification would be to convey information—not an instruction to implement. The hierarchy of authority is known by the Transmission Operator and other registered entities. This is known even if they are members of differing market structures, contract arrangements, or other organizational arrangements; thus the Transmission Operator will know the effective path of communications to use.		
Roger C Zaklukiewicz		Requirement R1 needs to be modified as the following terms in 1.1 are problematic to compliance and enforcement. Remove the term "but not limited to". Why must the data to be exchanged include that on all facilities that operate at levels lower than the Bulk Electric System to ensure the reliability of the interconnected BES - especially if the BES is to be recognized as the "bright line" transmission system that operates at 100 kV or above.
Response: The SDT believes you intended these comments for TOP-003, Requirement R1. Please see the responses to TOP-003 comments.		

Organization	Yes or No	Question 2 Comment
California ISO	Affirmative	The ISO supports the changes made in TOP-002-3 but notes that the "Seasonal Assessment" previously required by TOP-002-2 is no longer addressed in the TOP-002-3 wording. Is this an oversight or is this seasonal assessment going to be contained elsewhere?
Response: The SDT places reliability emphasis upon a daily assessment for the next day (hence the Operational Planning Analysis). The entity could have a library of various OPAs from which to select an appropriate one for assessment, or could develop an OPA each day (or even more often), but is not required to do so.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	The term "anticipated ... Contingency event conditions" in R1 is not a NERC defined term and could be interpreted as requiring analysis of all contingencies including extreme events. The requirement should clarify if it only applies to certain types such as category P1 or whether each TO can independently select which types of contingencies they anticipate. One suggested form or rewording the requirement could be: R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal conditions and TPL-001-2 category P1 Single contingencies.
Response: The Operational Planning Analysis (OPA) is a defined term and includes "expected system conditions" for the next day. The Contingencies which would apply are presented in the TPL standards. The Transmission Operator must address, at a minimum, the Contingencies presented, but may address more than what is required. Further, Facility Ratings and Stability Limits are defined terms and the FAC standards present the level of Contingencies that must be addressed in the Facility Ratings and SOLs methodologies. To specify only the proposed P1 single Contingencies may be too limiting. No change made.		
Tennessee Valley Authority	Affirmative	Further clarification is needed on the phrase - "internal area reliability".
Progress Energy	Yes	A definition of "internal area reliability" is needed

Organization	Yes or No	Question 2 Comment
Response: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Associated Electric Cooperative, Inc.	Yes	R1 Rationale Change: Rework or remove entirely Rationale: The R1 Rationale section does not match the R1 requirement as currently worded, and frankly is impossible, within the timing constraints of next-day analysis. (Example: PSS/E is technically a tool for steady-state network analysis. Without that tool, or a similar network-analysis tool being available, such analysis would be impossible by hand.) R3 Requirement wording Change: "in the plan(s)" To: "in the N-1 contingency-related plan(s)"Then Append: ", N-2 related contingency-plan(s) should be omitted unless highly plausible." Rationale: This recommended change seeks to avoid information overload on neighbors, while still encouraging more in-depth near-term contingency planning.
Response: R1 rationale box: The SDT has eliminated the rationale box. Requirement R3 deals with operations planning; thus the notification would be to convey information—not an instruction to implement. The hierarchy of authority is known by the Transmission Operator and other registered entities. This is known even if they are members of differing market structures, contract arrangements, or other organizational arrangements; thus the Transmission Operator will know the effective path of communications to use. The plans are limited to those developed in Requirement R2. No change made.		
Independent Electricity System Operator	Yes	We assess that the industry's comment on R3 regarding the need to inform all NERC registered entities identified in the plan(s) was due to the absence of a requirement to identify these entities. We therefore suggest to revise Requirement R2 to drive home the need to identify registered entities that are included in the plan(s) to operate to within IROL and SOL, and set the stage for R3:Each Transmission Operator

Organization	Yes or No	Question 2 Comment
		shall develop a plan, and identify the entities that will be required to implement actions, to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
Response: The SDT believes the current wording of Requirement R3 is sufficient. No change made.		
American Electric Power	Yes	R2: Once again, it needs to be clarified whether this requirement is in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader.
Response: TOP-002-3 is about Operations Planning, thus it cannot be addressing actual Real-time flow. It addresses those flows contained in the Operational Planning Analysis (OPA) and the assessment thereof. Based upon that assessment and the OPA, the Transmission Operator will develop a plan to operate. No change made.		
NIPSCO	Yes	None at this time
Dairyland Power Cooperative	Yes	
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	
Omaha Publc Power District	Yes	
Texas Reliability Entity	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 2 Comment
US Bureau of Reclamation	Yes	
Xcel Energy	Yes	
FirstEnergy	Yes	
Dominion	Yes	
PacifiCorp	Yes	
Lincoln Electric System (LES)	Yes	
LG&E and KU Serivces	Yes	
Western Area Power Administration	Yes	
FMPP	Yes	
Luminant Energy Company, LLC	Yes	
Response: Thank you for your support.		

3. **The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: There were a number of requests for clarification which the SDT have addressed either through changes to the language of the requirements or through specific responses to those comments. There was one substantive change to the standard – the addition of the Distribution Provider to the list of applicable entities in general and to Requirement R5 specifically.

The SDT changed the effective date for all requirements in proposed TOP-001-2, TOP-002-3, and TOP-003-2 to 12 months in response to comments except for proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.

The following changes have been made due to industry comments:

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. The specification shall include:

R3. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.

R4. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification as developed in Requirement R1to entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R2. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R~~4~~5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

Data Retention 4. Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~and operating analysis assessment processes and tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R4 and Measurement M4.

Organization	Yes or No	Question 3 Comment
Luminant Energy	Abstain	TOP-003-2 as currently written does not provide any recourse for the entity receiving a data request if that entity feels the data request is unreasonable either in content or timing or if the entity does not have the data available to submit. As such I would recommend modify R5 as follows: R5. Each......shall satisfy the obligations of the documented specification for data. R5.1. If the entity receiving the data request cannot provide the requested data either in content or timing then the entity receiving the data request shall notify the requesting entity and provide a reason for not providing the data.
Kansas City Power & Light	No	These requirements do not recognize the limitations of data exchange capability with an entity and the sources of data an entity has. Recommend these requirements be modified to include "within the data exchange capabilities and data available of the recipient of the data specification".
City Water Light and Power (CWLP) - Springfeild - IL	No	R1 and R2 require specifications for data exchange which do not account for the ability of the respondent to meet the specification. As written, the requirement could force a respondent to continue to provide data with such a format, periodicity,

Organization	Yes or No	Question 3 Comment
		or deadline that would be an undue burden to the respondent. All requirements should explicitly stress a mutually agreed plan and R1.1/R2.1 should refer to classes or types of as a qualifier. Likewise, R5 should explicitly state that respondents shall satisfy the obligations within the context of a mutually agreed specification.
Dairyland Power Cooperative	No	R1 and R2 refer to "A periodicity for providing data" and "The deadline by which the respondent is to provide the indicated data". What if this specification is unreasonable? To address this concern, DPC suggests adding the words "mutually agreeable" as was used in reference to the format specification.
Response: Requirement R1 should prevent a Transmission Operator from requesting data that another entity can't provide. There are arbitration processes available to straighten these matters out if all else fails. No change made.		
Muscatine Power & Water, MidAmerican Energy Co.	Negative	There is a great possibility of double jeopardy when R3 and R4 have in part the statement of "...in meeting its NERC-mandatory reliability requirements." So, an Entity could be found non-compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown "...in meeting its NERC-mandatory reliability requirements," then they would be found non-compliant with this Standard. It is not clear why this Standard is being written with the statement of "...in meeting its NERC-mandatory reliability requirements."
US Army Corp of Engineers	No	Issue: There is a great possibility of double jeopardy when R3 and R4 have in part the statement of in meeting its NERC-mandatory reliability requirements. So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown in meeting its NERC-mandatory reliability requirements then they would be found non compliant with this Standard. It is not clear why this Standard is being written with the statement of: in meeting its NERC-mandatory reliability requirements. As stated in the NERC Standard Process Manual, under Background, NERC works with all stakeholder segments of the electric industry, including electricity users, to develop standards for the reliability planning and

Organization	Yes or No	Question 3 Comment
		reliable operation of the bulk power systems. Recommend that in meeting its NERC-mandatory reliability requirements, be deleted and replaced with reliable operation as defined as operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance. Or, please review IRO-010-1a, requirement 1 and use like terminology for this Standard.
Lincoln Electric System (LES)	No	Please refer to comments submitted by MRO's NERC Standards Review Forum for LES' concerns related to TOP-003.
MRO-NSRF	No	Issue: There is a great possibility of "double jeopardy" when R3 and R4 have in part the statement of "...in meeting its NERC-mandatory reliability requirements." So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown "...in meeting its NERC-mandatory reliability requirements" then they would be found non compliant with this Standard. It is not clear why this Standard is being written with the statement of: "...in meeting its NERC-mandatory reliability requirements". As stated in the NERC Standard Process Manual, under Background, "NERC works with all stakeholder segments of the electric industry, including electricity users, to develop standards for the reliability planning and reliable operation of the bulk power systems. Recommend that "...in meeting its NERC-mandatory reliability requirements", be deleted and replaced with "reliable operation" as defined as "...operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance...". Or, please review IRO-010-1a, requirement 1 and use like terminology for this Standard.
Response: The SDT views the requirements as two separate and distinct actions. In Requirements R1 and R2, the entity is developing the specification and in Requirements R3 and R4 the entity is distributing the specification. Therefore, there is no double jeopardy.		

Organization	Yes or No	Question 3 Comment
No change made. This standard exactly matches IRO-010-1a in content and intent. No change made.		
Volkmann Consulting, Inc.	Negative	TOP-003-2 R5 does not adequately replace PRC-001 R2. TOP-003-2 R5 does not require notifying the RC and drops the requirement of GOP to analyze equipment and relay failures, TOP-003-2 R5 states GOP obligations as specified in R3 and R4, however R3 and R4 are not applicable to GOP.
Response: There is nothing in PRC-001-1, Requirement R2 about analysis. The SDT believes you are thinking of PRC-004-2a, Requirement R2 which is not part of this project and is not intended to be replaced by the revised standards. No change made.		
Northeast Power Coordinating Council	No	TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates the TO, LSE, and Generator Owners to provide this real-time data. These entities provide a wealth of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.TOP-003 R5 has only a severe VSL. Data providers can provide hundreds if not thousands of points to TOPs. If one RTU goes down is the data provider going to be assessed a severe VSL? TOP-003-2 R1.1 states: R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: Long term outages of Bulk Electric System (BES) Facilities. Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES NPCC believes language such as but not limited to and levels lower than the BES to be problematic and beyond the scope of what is needed in the standard and also creates potential for compliance issues.
United Illuminating Company	No	TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates TO, LSE, and Generator Owners to provide this real-time data. These entities provide a multitude of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It

Organization	Yes or No	Question 3 Comment
		is not clear to UI that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.
Response: It is not the intent of the SDT that TOP-003-2 penalizes entities for communication errors. The intent is to have the data communications established. Communication errors are handled in the COM standards. No change made.		
Dominion	No	If this question was meant to refer to TOP-003-2, then Dominion offers the following comments: M5 reads "Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities." Since R2 was added, Dominion suggest M5 should read as "receiving a data specification in Requirement R3 or R4 shall make available evidence that is has satisfied the obligations of the documented specifications for data in accordance with Requirement R5....".
Response: The SDT agrees and has changed measure M5 accordingly. **M5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R~~4~~5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.		
SERC OC Standards Review Group	No	There appears to be ambiguity for R1 and R2 - is the VSL applicable to the TOP/BA requesting the data or is it applicable to the TOP/BA providing the data? If it applies to the TOP/BA requesting the data we would suggest that the SDT be consistent with

Organization	Yes or No	Question 3 Comment
		the VSLs in IRO-10-1a.
Response: The SDT does not see the confusion pertaining to Balancing Authority/Transmission Operator that the VSLs in Requirements R1 and R2 apply. The requirement is for the Transmission Operator/Balancing Authority to document a specification, it would have to be the Transmission Operator/Balancing Authority writing the specification and ultimately requesting the data through Requirements R3 and R4. No change made.		
Constellation Energy	No	The Drafting Team may want to consider addressing a time period for responding to a data request to ensure parties are given time to respond. For example, a BAs data request may be driven by the TOP's data request. If a BA receives a data request for information from the TOP that sources from a GOP, the BA will need to establish a data request from the GOP that has the same deadline. If the GOP is unable to supply the data they may be non-compliant if they do not meet the deadline.
Response: Parts 1.4 and 2.4 discusses a deadline for responding to the data request. No change made.		
ACES Power Marketing Member Standards Collaborators	No	We largely agree with the changes but have identified the following specific issues.We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Because of the difficulties experienced by some entities in receiving the RC data specification in IRO-010-1a, we recommend that the implementation of TOP-003-2 Requirement R5 occur a couple of months after the implementation in TOP-003-2 Requirements R1-R4. IRO-010-1a is a parallel standard to TOP-003-2 and the effective date of the distribution of the RC data specification was simultaneous to

Organization	Yes or No	Question 3 Comment
		the effective date of the requirement for the recipients to comply with the data specification. This meant that the RC could provide the data specification on the same date that the recipients had to meet the data specification. Unfortunately, there were some entities expecting to receive the data specification that did not and were concerned about a potential non-compliance. What if an auditor determined the RC should have provided the data specification? Would the entity that expected to receive the data specification be held responsible? By staggering the effective date of Requirement R5, this confusion can be avoided.
Southwest Transmission Cooperative, Inc.	Affirmative	We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Because of the difficulties experienced by some entities in receiving the RC data specification in IRO-010-1a, we recommend that the implementation of TOP-003-2 Requirement R5 occur a couple of months after the implementation in TOP-003-2 Requirements R1-R4. IRO-010-1a is a parallel standard to TOP-003-2 and the effective date of the distribution of the RC data specification was simultaneous to the effective date of the requirement for the recipients to comply with the data specification. This meant that the RC could provide the data specification on the same date that the recipients had to meet the data specification. Unfortunately, there were some entities expecting to receive the data specification that did not and were concerned about a potential non-compliance. What if an auditor determined the RC should have provided the data specification? Would the entity that expected to receive the data specification be held responsible? By staggering the effective

Organization	Yes or No	Question 3 Comment
		date of Requirement R5, this confusion can be avoided.
Response: The purpose of the standard is to address reliability needs. Any concerns about BES vs. BPS in standards are better directed toward the NERC Standards Committee. No change made. The SDT has changed the effective date for the implementation of this project to 12 months except for proposed TOP-003-2, Requirements R1 and R2 which will be in 10 months.		
LG&E and KU Serivces	No	LG&E and KU Services do not believe that data/evidence retention requirements should be modified by the Compliance Enforcement Authority. This potentially will result in different data retention requirements across regions. A Compliance Enforcement Authority should enforce only what is written within the standard and not have the option of expanding the requirement. 4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.
Response: The SDT is using standard boilerplate language in the Data Retention section. It is not within the scope of the SDT to alter such language. Questions about such situations should be taken to the NERC Standards Committee. No change made.		
Georgia System Operations	No	R5 is too unilateral. A TOP could send a spec to an entity for some data that the entity is not able to provide and per this requirement the entity will still be required to provide it. There must be some mutual agreement to more than just the format. There must be agreement to what can be provided and that the data is needed by the TOP's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements. Also some provision must be allowed to cover when data or the transfer method is unavailable (e.g., when an RTU goes down). A similar situation applies to BAs sending a spec to an entity.
Response: Requirement R1 should prevent a Transmission Operator from requesting data that another entity can't provide. If all else		

Organization	Yes or No	Question 3 Comment
fails, there are arbitration processes to clear up such matters. No change made.		
Western Area Power Administration	No	Data an entity specifies in requirement documents need to have some kind of reasonability limit or explanation as to what the data will be used for. As written a TOP or BA can request anything they want and other entities will be required to provide that data, even if the requested data is not available as requested. An entity can also request data not pertinent to the reliability of their system and other entities will still be required to provide it. An entity required to provide the data should have an opportunity to challenge the need for data requested. At least one BA in WECC is running a market and data provided will be used in their market, not for reliability.
Response: Requirement R1 clearly states that the data requested must be for use in an entities Real-time monitoring function or for its Operational Planning Analysis. This restricts the data to reliability oriented data. No change made.		
We Energies	No	R1.4 and R2.4: The deadline must allow time to gather and send the data. If the TOP said immediately, you would be immediately non-compliant. In addition, R2 should include data necessary to perform at least Next Day analysis, even Operational planning Analysis. R5 needs to include the DP. Data Retention: Each bullet states that monitoring is required in accordance with Measures. Measures cannot be requirements.
Response: The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. There are arbitration processes available if all else fails. No change made. Balancing Authorities do not perform Operational Planning Analyses as this is a transmission-oriented task. However, the SDT has inserted a phrase to cover analyses. **R2**. Each Balancing Authority shall create a documented specification for the data necessary for it to perform analysis functions and its required Real-time monitoring. The specification shall include:		

Organization	Yes or No	Question 3 Comment
The SDT agrees. **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. The inclusion of requirements and measures in data retention is standard language and simply ties the data retention language to the requirements and measures together. It does not imply that the measures are requirements. No change made.		
American Transmission Company, LLC	No	In the introduction to this question, the Standard number should be corrected to TOP-003-2. Requirement 1- A data specification must have bounds. There is nothing that would preclude a request for data that is not achievable yet is mandated to be satisfied by Requirement 5. Requirement 1, sub-Requirement 1.2 may never be arrived at given the former.
Response: The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. There are arbitration processes available to straighten these matters out if all else fails. No change made.		
Omaha Publc Power District	No	OPPD is requesting clarification on operational data requirements (R1 and R3) related to "documented specification for the data necessary for it to perform..." What the document should include that is specifying operational data request from or to other Transmission Operators. Additionally, how often operational data specification document should be provided/updated to or from other Transmission Operators.
Response: The SDT believes it is clear as to what is required – the data needed to perform the entities Real-time monitoring and Operational Planning Analyses. No change made. Requirement R1, Part 1.3 covers the periodicity issue. No change made.		
Manitoba Hydro	No	M1 – This measure goes beyond the requirements of the standard, as there is no

Organization	Yes or No	Question 3 Comment
		requirement for a specification document to be dated. Manitoba Hydro suggests either striking 'dated' from M1 or adding the requirement to have a 'dated documented specification' to R1. M2 – Same comment as M1. Manitoba Hydro suggests either striking 'dated' from M2 or adding the requirement to have a 'dated documented specification' to R2. A R3 - For consistency with R1 and overall clarity, Manitoba Hydro suggests changing the wording of R3 to 'Each Transmission Operator shall distribute its documented specification developed in accordance with R1 to those entities that have data required by the Transmission Operator to support its Operational Planning Analysis and Real-time monitoring '. The VSL for R3 should be changed accordingly as well. R4 - For consistency with R2 and overall clarity, Manitoba Hydro suggests changing the wording of R4 to 'Each Balancing Authority shall distribute its documented specification developed in accordance with R2 to those entities that have data required by the Balancing Authority to perform its Real-time monitoring'. The VSL for R4 should be changed accordingly as well.
Response: M1/M2: The requirements refer to deadlines which imply a timing element so it is permissible to add 'dated' to the measures as adherence to a deadline doesn't make much sense otherwise. No change made. R3/4: The SDT does not feel the suggested change adds further clarification. No change made.		
E.ON Climate & Renewables	No	ECRNA appreciates the efforts of the drafting team in eliminating duplicative requirements and efforts, as this is an important part of developing clear and concise standards. However, we are concerned about the end result of an unbounded data specification. Although requirements R1 through R4 are directed toward the Balancing Authority and Transmission Operator, these requirements have a direct impact on the other applicable entities. The lack of guidance to and expectations of the data and format could and most likely will lead to a wide range of data specifications from the multitude of Balancing Authorities and Transmission

Organization	Yes or No	Question 3 Comment
		Operators in North America. Entities that own or operate facilities in multiple regions and work with many BAs and TOPs may have difficulty responding to each individual specification's needs, including timeframe, and format. Also considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable. In addition, the sub-requirements to R1 and R2 could be written more clearly to identify who the TOPs and BAs are expected to mutually agree with and request information from. One can assume the applicable entities listed in the standard, but explicitly stating this within the standard is a better method and ensures entities are provided an opportunity to provide input in the data specification format.
Response: The data specification concept provides entities with flexibility in crafting the specifications to the exact data that it needs to perform its tasks. Data specifications may be different for the same type of entity within a Transmission Operator Area let alone in different regions of the country. Guidance is provided within the requirement on format, etc. No change made. The severity factor on Requirement R5 is based on its level of importance and its relationship to a similar requirement in IRO-010-1a which has been approved by FERC. No change made. The SDT sees no reliability value in duplicating a list within the bounds of the requirement itself. No change made.		
Texas Reliability Entity	No	Regarding R1, we are concerned that the proposed requirement gives each TOP too much latitude to determine what data it considers necessary. This may cause confusion due to significant differences in data specified by different TOPs and the ability of TOPs to unilaterally change their data specifications. We would prefer that the standard include a basic list of data to be included in the specification. The reference to "mutually agreeable format" in R1 part 1.2 is problematic because it allows the respondents to interfere in the TOP's data collection process. The TOP should be allowed to dictate a reasonable format for data submission. In R2, we are opposed the removal of "Operational Planning Analyses" (OPA) for a Balancing Authority in this requirement, because the BA is "the responsible entity that

Organization	Yes or No	Question 3 Comment
		integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time." A BA should create a documented specification for the data necessary for it to perform an OPA just as a TOP does. The reference to "mutually agreeable format" in R2 part 2.2 is problematic because it allows the respondents to interfere in the BA's data collection process. The BA should be allowed to dictate a reasonable format for data submission. In R3 we suggest changing "operating analysis" to "Operational Planning Analysis," which is a more precise term for what appears to be intended. The same change should be made in Measure M3. In R4 we suggest adding "Operational Planning Analysis," to be consistent with our comment that R2 should require "Operational Planning Analysis" data in the BA's data specification. In the Measures, please check and correct the references to Requirement numbers - some references are to the wrong requirements. Under Data Retention, in the 4th bullet starting with "Each Balancing Authority...", the phrase "and operating analysis assessment processes and" should be struck because it does not align with requirement R4 as currently written. However, we support adding "Operating Planning Analysis" in R4, and this data retention reference should be consistent with the requirement.

Response: The requirement is designed to give the Transmission Operator the flexibility it needs to get the data it requires. It is bound by the provision for data needed to support its Real-time monitoring and Operational Planning Analyses. It is absolutely true that different Transmission Operators may be specifying different data due to their differing operational requirements. Supplying a basic list of data does not provide this flexibility and does not ensure that all data needed would be in the list. No change made.

It is unreasonable to allow a Transmission Operator or any other entity to arbitrarily introduce a format that other entities can't support. There has to be some degree of mutual agreement to decisions of this type in order to be fair to all parties involved. The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of

Organization	Yes or No	Question 3 Comment
reliability. There are arbitration processes available to straighten these matters out if all else fails. No change made. A Balancing Authority can't perform an Operational Planning Analysis by definition since this defined term only applies to transmission-oriented analysis. However, the SDT has added wording to cover analyses. **R2**. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. The specification shall include: R3 – The SDT agrees and has made the language consistent. R3. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. The SDT has changed Requirement R4 to be consistent with the revised Requirement R2. **R4**. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. The references in the Measures have been corrected. The SDT agrees and has made the suggested change consistent with the responses concerning requirement R2 above. **Data Retention 4**. Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~and operating analysis assessment processes and tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R4 and Measurement M4.		
Indiana Municipal Power Agency	No	IMPA believes that the entities (Transmission Operator and Balancing Authority) should be required to create a documented specification that lists exactly what the entities (in R5) need to provide to them to meet the requirement and not be allowed to say that "it is in our manuals and/or agreements." When the Transmission Operator and/or Balancing Authority only references their manuals, it is up to the entity (in R5) to read the manuals that are referenced and then try to come up with a documented specification listing on their own which may or may not include

Organization	Yes or No	Question 3 Comment
		everything that is required by the TO or BA which makes the current draft standard's language very ambiguous. IMPA is not objecting to these entities using manuals as long as a specific documented specification is created and distributed that does more than just list the name of manuals. The documented specifications need to be detailed in what is required from entities to aid in preventing possible non-compliance issues due to an entity missing an item in a manual or including unnecessary items due to being left to their own interpretations.
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by Indiana Municipal Power Agency concerning the need for clearer communication of data specifications in R3 and R4 in order to facilitate compliance with R5.
Response: The intent of Requirements R1 and R2 is for the entity's to do exactly what is cited in your comment. The entity must spell out each piece of data it requires and specify it to the affected entity who will be supplying the data. No change made.		
US Bureau of Reclamation	No	The language change in R1 has not been incorporated into the sub requirements. The requirement R1 was modified to eliminate the second party. A mutual agreement is required in R 1.2 but only party is listed in R1. The language should specify that the TOP is to coordinate its data requests with the appropriate entities and seek mutal agreement on the format.
Response: The SDT believes it is clear who must agree to the format and sees no additional clarity being provided by listing the entities in the text of the requirement. No change made.		
Xcel Energy	No	Applicability - why are Distribution Providers not subject to this standard? Is it possible that a TOP or BA may need information form a DP to perform an "OPA"? "Mutually agreeable" in 1.2 should be removed. The TOP and BA should work with the subject entities, however stating that something must be mutually agreed upon could create delivery and acceptance of data in a less than desired form solely to meet the words of the requirement.

Organization	Yes or No	Question 3 Comment
Response: The SDT agrees and has added the Distribution Provider to the applicable entities and to Requirement R5. **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. There are arbitration processes available to straighten these matters out if all else fails. No change made.		
ReliabilityFirst	No	ReliabilityFirst has the following comments for consideration:1. R1 and R2 - ReliabilityFirst recommends changing the phrase “shall create...” to “shall have...” in R1 and R2. 2. R1 and R2 - ReliabilityFirst recommends changing Part 1.2 and Part 2.2 to state “A format”. ReliabilityFirst believes it may be difficult to audit and enforce the phrase “mutually agreeable”. 3. R3 - ReliabilityFirst seeks clarification on the term “operating analysis assessment” used in R3. Is this language referring to the Transmission Operators Operational Planning Analyses as required in R1? If not, can the SDT clarify what the phase “operating analysis assessment” is referring to? 4. R3 and R4 - ReliabilityFirst seeks clarity on what the phrase “NERC-mandated reliability requirements” is referring to? Is it referring to FERC approved NERC standard requirements or does it encompass NERC Directives, CANs, NERC bulletins, etc. as well? 5. R3 and R4 - R3 references “those entities” and R4 just references “entities”. ReliabilityFirst recommends modifying either R3 or R4 to use consistent language. 6. Data retention - ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example the last sentence states “the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full

Organization	Yes or No	Question 3 Comment
		time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.
Response: The SDT does not believe that the suggested change provides any additional clarity. No change made. The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. The suggested change does not clarify the situation further than what is already written. There are arbitration processes available to straighten these matters out if all else fails. No change made. The SDT has changed requirement R3 for clarity. R3. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. The phrase is in reference to approved Reliability Standards. The SDT agrees and has changed Requirement R3 accordingly. The SDT is utilizing NERC supplied boilerplate language in the Data Retention section. It is out of the scope of this project to make changes to that language. No change made.		
Nebraska Public Power District	No	Comments: Requirements R1 & R2 do not put any meaningful bounds on the data that a TOP or BA may request in the name of monitoring real-time operations. There is no check or balance on spcifying timeframes when the data is required either. Attachment 1 TOP-005-1 contained the type of data that may be required and as such provided a fremework for what type of data was required for real-time monitoring of the Bulk Electric System. As written, it would be possible for a BA or TOP to request data that a registered entity does not have available and require it in an unrealistic timeframe. This puts those entities in a position where they cannot comply with the standard, even though the data requested may not be important in

Organization	Yes or No	Question 3 Comment
		the monitoring of the Bulk Electric System. There need to be reasonable limits on the information requested and how quickly new information may be required from other registered entities.
Response: Requirements R1 and R2 are bound by the language restricting the specifications to Real-time monitoring or Operational Planning Analysis. This restricts the data requested to be only for reliability-related purposes. No change made.		
Ameren	No	R1. Each TOP shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: 1.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the TOP. This is illogical and needs to be clarified or removed. 1.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R2. Each BA shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. The specification shall include: 2.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the BA. This is illogical and needs to be clarified or removed. 2.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R3. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert “from R1” There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they

Organization	Yes or No	Question 3 Comment
		should be spelled out explicitly here and likely in R1 as well. R4. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert "from R1" There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they should be spelled out explicitly here and likely in R1 as well. R5. We recommend re-writing: "Each TOP, BA, GO, GOP, IA, LSE, and TO receiving a data specification in Requirement R3 or R4 shall provide the data associated with said data specification. "

Response: R1.2/R2.2**:** The SDT believes that the context is clear and that duplicating a list of entities in the language of the requirement does not provide any additional clarity. No change made.

R1.4/R2.4:The SDT believes that there is no additional clarity provided in the suggested language. No change made.

R3/R4: The SDT does not see any additional clarity provided by the suggestion. No change made.

R3/R4: The term refers to the approved reliability standards. No change made. The SDT has changed the requirements for consistency of wording.

> **R3**. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.
>
> **R4**. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.

R5: The SDT sees no additional clarity being provided by the suggested change. No change made.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>GTC</td><td>No</td><td>M4 is misreferencing R2 and R4 and should be corrected as follows: ....”receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R5.”</td></tr>
<tr><td colspan="3">**Response:** The SDT believes that you meant Measure M5. The references have been corrected.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R~~4~~5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.</td></tr>
<tr><td>Intellibind</td><td>No</td><td>There is no assurance that in R1 and R2 that the format designated by the BA or TOP is Mutually Agreed by the parties. It will be essentially impossible for auditors to destinguish what is directed vs. what has been negotiated.</td></tr>
<tr><td colspan="3">**Response:** There is no need to distinguish between the two cases. The only one that is pertinent is what the two parties have agreed upon. No change made.</td></tr>
<tr><td>Progress Energy</td><td>Yes</td><td>Please include "operational Planning Analyses" in R2 as you have in R1.</td></tr>
<tr><td>California ISO</td><td>Affirmative</td><td>The words “and Operational Planning Analyses” should be added to the end of the first sentence in R2 (the Operational Planning Analysis is included in R1).

A similar addition should be made to R4.</td></tr>
<tr><td colspan="3">**Response:** By definition, the Balancing Authority can’t perform an Operational Planning Analysis as it is a transmission-oriented task. However, the SDT has added wording to cover analyses.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform analysis functions and its required Real-time monitoring. The specification shall include:</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power</td><td>Affirmative</td><td>If a Transmission Operator or a Balancing Authority is requesting data from another entity, they must demonstrate a reliability impact validating the need for the requested data.</td></tr>
<tr><td colspan="3">**Response:** Demonstrating the need would be an onerous task with no reliability benefit. The Transmission Operator and Balancing Authority are constrained as to what they can request by the language in the requirements. They can only ask for what is needed to support their assigned tasks. No change made.</td></tr>
<tr><td>City of Tallahassee</td><td>Affirmative</td><td>While it specifies that the examples are only possibilities for evidence, the inclusion of “with acknowledgement” to “web postings” in M2 & M3 for TOP-003-2 will become onerous. It requires another entity to respond in order to have evidence we were compliant.</td></tr>
<tr><td colspan="3">**Response:** The SDT believes you meant Measures M3 and M4 but agrees and has changed the measures accordingly.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification as developed in Requirement R1to entities that have data required by the Transmission Operator’s ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R2. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority’s analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.</td></tr>
<tr><td>NIPSCO</td><td>Yes</td><td>In R3 & R4 the phrase "in meeting its NERC-mandated reliability requirements" is too open-ended and may be difficult to comply with. This should be more specific; what requirements are these.</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
Response: The phrase encompasses the approved reliability standards. No change made.		
Associated Electric Cooperative, Inc.	Yes	TOP-003-1 R1, R2, and R3 Guidelines Add: Guidelines Section - These requirements are all written as highly TOP-centric and BA-centric, without regard to the confusion and work-load a single published plan could cause small entities. If hundreds or perhaps thousands of data-points are cited within a uniformly circulated plan, yet some entities provide only one or two obscure points within that plan, then the TOP or BA is being unnecessarily inconsiderate, and should have appropriately filtered that request for their audience. Rationale: Very large TOPs or BAs would benefit from being reminded that they need to consider their audience when sending out plans as data-requests to small entities. There is no need to overwhelm smaller entities with a lot of unrelated data, or data that does not seem to match their own identifiers. We can do better.
Response: The SDT understands the smaller entities perspective. Each entity will be provided a data specification that is unique to them with only the data that they can provide included. No change made.		
Independent Electricity System Operator	Yes	We agree with the addition of R2, but have a concern over Measure M2, which says:M2: Each Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R2.The wording “dated, current, in force” does not reflect what’s in the requirement R2, and is not necessary. This wording pertains to the data retention requirement, which is already included in the second bullet in Section D, 1.3 - Data Retention:”Each Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.”We suggest to remove this wording from M2.
Response: The requirement refers to deadlines which imply a timing element so it is permissible to add ‘dated’ to the measures as adherence to a deadline doesn’t make much sense otherwise. No change made.		

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	Although we would prefer to see a consolidated RC-BA-TOP data specification, Ingleside Cogeneration LP agrees that TOP-003-1 is a good first step in that direction. Any help the SDT can provide to reduce overlap in data requests and to drive to a common format is appreciated.
Response: The requirement is designed to give the Transmission Operator/Balancing Authority the flexibility it needs to get the data it requires. It is bound by the provision for data needed to support its Real-time monitoring and Operational Planning Analyses. It is absolutely true that different Transmission Operators/Balancing Authorities may be specifying different data in different formats due to their differing operational requirements.		
Duke Energy	Yes	o R1.1 - Consistent with our Question #1 comment above on using the actual wording of the BOT-approved definition of "Adverse Reliability Impact" since it has not yet been approved by FERC, "Operational Planning Analysis" has likewise not yet been approved by FERC as of the latest version of the Glossary posted on the NERC website, December 13th, 2011. Suggest using the wording of the defined term. If the SDT decides to instead keep the defined term, "Analyses" should be "Analysis". o R3 - Current wording is awkward. Suggest rewording as follows: "Each Transmission Operator shall distribute its data specification to entities that have data required for operating analysis assessment processes and reliability monitoring tools used by the Transmission Operator in meeting its NERC-mandated reliability requirements." o R4 - Current wording is awkward. Suggest rewording as follows: "Each Balancing Authority shall distribute its data specification to entities that have data required for reliability monitoring tools used by the Balancing Authority in meeting its NERC-mandated reliability requirements." o Measures and Data Retention - change to align with suggested R3 and R4 rewording above.
Response: Adverse Reliability Impact and Operational Planning Analysis are FERC approved terms. Adverse Reliability Impact was		

Organization	Yes or No	Question 3 Comment
approved on March 16, 2007 and Operational Planning Analysis was approved on March 17, 2011. The Transmission Operator could be running more than one Operational Planning Analysis thus the use of the plural term. No change made. The SDT does not see any additional clarity from the suggested change. However, the SDT has changed Requirements R3 and R4 due to other comments. Measures and Data Retention have been updated accordingly. **R3**. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. **R4**. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.		
American Electric Power	Yes	R5: It should be noted that some of the information that could potentially be requested may already be available, for example on reliability coordinator systems. AEP suggests that the requirement be modified so that it does not unintentionally create an edict to provide "any data" to parties simply because R5 could be interpreted as allowing requests of any kind. The possibility of a dispute resolution process managed by the reliability coordinator(s) might also address these possible scenarios. Such a process should address, at a minimum, specifics such as timing, format and general logistics concerning the requested data. AEP does not currently have any text to suggest in this regard, but asks the SDT to consider such a change.
Response: Requirement R5 is bound by the constraints of Requirements R1 and R2 so that not just any information can be requested. There are arbitration processes available to resolve disputes. No change made.		
Bonneville Power Administration	Yes	BPA is in support of standard TOP-003-1, due to the importance of being able to receive data.
ISO/RTO Standards Review Committee	Yes	

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	
Imperial Irrigation District (IID)	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
PacifiCorp	Yes	
Southwest Power Pool Regional Entity	Yes	
FMPP	Yes	
South Carolina Electric and Gas	Yes	
Oklahoma Gas and Electric	Yes	
Westar Energy	Yes	
Pepco Holdings Inc	Yes	
NV Energy	Yes	
ISO New England Inc.	Yes	
Response: Thank you for your support.		

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: Several comments state that the VSLs for TOP-003-2, Requirement R5 were more stringent or severe than the VSLs for the TOP-003-2, Requirements R1-R4. The SDT views Requirements R1-R4 as enabling requirements for making clear what data is required for the responsible entities in Requirement R5 and believe the VSLs align with the stated purpose of the standard to ensure the Transmission Operator and Balancing Authority have the necessary data "to fulfill their operational planning and Real-Time monitoring responsibilities". Several other comments shared the view that the VRFs and VSL for Requirements R1-R4 were not consistent with Requirement R5. The SDT views Requirements R1 – R4 as enabling requirements leading to Requirement R5. The purpose of TOP-003-2 is to make sure the Transmission Operator and Balancing Authority have the data necessary for fulfilling their functional obligations. Thus, the real crux of the standard is to supply data. No changes were made due to these comments.

Changes made due to comments are:

TOP-001-2, Data Retention: Changed retention requirement for voice recordings to 90 calendar days from three calendar months.

TOP-001-2, Requirement R1 VSL: The Severe VSL was reworded for clarity.

TOP-001-2, Requirement R3 Moderate VSL modified by inserting "affected" for consistency with the requirement and other VSLs.

TOP-001-2, Requirement R5 VSLs: A note prior to the VSLs was removed. The note was a vestige from a previous posting explaining how to use the VSLs when both percentages and integers are used in the VSL. Percentages were removed during that past posting and the note should have been removed as well.

TOP-001-2, Requirement R10 VSLs: Changed "has been" to "had been".

TOP-002-3, Requirement R3 Lower and Severe VSLs were modified based on comments and to make them consistent with Moderate and High VSLs. More specifically, the "whichever is less" language was added to the Lower VSL.

TOP-003-2, Requirements R1 and R2 VSLs: Replaced elements with ~~Parts~~ parts to clarify that it is the ~~Parts~~ parts of the requirements that are missed.

TOP-003-2, Requirements R1 and R2, Severe VSL: Changed "four or more" to "four" since there are only four parts.

TOP-003-2, Requirements R3 and R4 VSLs: Added "boiler plate" explanation for how to select if the integer or percentage value is used in selecting the VSL.

No changes were made for the following comments:

TOP-001-2, Requirements R3, R5, and R6 VSLs: A few comments suggested adding percentages to the integer VSLs. The SDT did not believe that probable sample sizes warranted use of percentages.

TOP-001-2, Requirement R5 VSL – Several comments indicated the VSL should be binary and Severe. The SDT disagrees that the VSL ought to be binary. Failure to notify one Transmission Operator of an Adverse Reliability Impact is not as Severe as failing to notify the Reliability Coordinator. Failure to notify the Reliability Coordinator is a Severe VSL. If the Reliability Coordinator knows, then the Reliability Coordinator will ensure the Adverse Reliability Impact is addressed.

TOP-003-2, Requirement R5 VSLs: Several comments indicated concern that the requirement could not be partially satisfied. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc.

Changes made are reflected below:

TOP-001-2, R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, ~~unless~~and such action would have violated safety,

				equipment, regulatory, or statutory requirements.

TOP-001-2, R3	The Transmission Operator did not inform one other Transmission Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis

TOP-001-2, R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, ha~~s~~d been exceeded.

TOP-002-3, R3	The Transmission Operator did not notify one NERC registered entity or 5% or less of the NERC registered entities whichever is less identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two NERC registered entities or more than 5% and less than or equal to 10% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three NERC registered entities or more than 10% and less than or equal to 15% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more NERC registered entities or more than15% of the NERC registered entities identified in the plan(s) as to their role in the plan(s).

TOP-003-2, R1	The Transmission Operator did not include one of the required ~~elements~~ parts (Part 1.1 through Part 1.4) of the documented	The Transmission Operator did not include two of the required ~~elements~~ parts (Part 1.1 through Part 1.4) of the documented	The Transmission Operator did not include three of the required ~~elements~~ parts (Part 1.1 through Part 1.4) of the documented	The Transmission Operator did not include four ~~or more~~ of the required ~~elements~~ parts (Part 1.1 through Part 1.4)

	specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring.	of the documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

TOP-003-2, R2	The Balancing Authority did not include one of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its required analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its required analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their required analysis functions and Real-time monitoring.	The Balancing Authority did not include four ~~or more~~ of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their required analysis functions and Real-time monitoring.

				OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its required analysis functions and Real-time monitoring.

Organization	Yes or No	Question 4 Comment
Luminant Energy	Abstain	The comments below are in reference to the VSL for TOP-003-2 R5: The VSL for TOP-003-2 R5 places a more stringent severity level on the entities receiving the data requests than it places on the entities that are responsible for creating the data requests. As such, I would suggest changing the VSL for TOP-003-2 R5 to the following: Lower: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy one of the obligations of the documented specification for data. Moderate: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy two of the obligations of the documented specification for data. High: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy three of the obligations of the documented specification for data. Severe: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy four or more of the obligations of the documented specifications for data.
Response: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation should only occur		

Organization	Yes or No	Question 4 Comment
for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. No change made.		
Lincoln Electric System (LES)	No	The word "affected" should be added to the Moderate VSL for TOP-001-2 R3 following "...known or expected to be affected by an actual...".
Response: The SDT agrees and has modified the Moderate VSL. See the redlined VSL in the Summary Consideration for this question to view the changes.		
Duke Energy	No	o TOP-001-2, R8 - Consistent with R3, the Time horizon for R8 should only be Operations Planning. o TOP-001-2 VSLs for R8 and R9 should be changed consistent with our suggested revisions to the requirements. Also see comment below regarding use of percentage ranges. o TOP-002-3 VSLs for R3 - the addition of the percentage range on the Lower VSL makes no sense. The "whichever is less" phrase on the other VSLs could push a violation into a higher VSL because of the percentage range. For example, if the TOP had 10 entities to notify and failed to notify one, then it would be a Moderate violation (10%) instead of Lower. If the TOP had 100 entities to notify and failed to notify four (less than 5%), then it would still be a Severe violation. o TOP-003-2 VSLs for R1 - "Analyses" should be "Analysis", since "Operational Planning Analysis" is a defined term. o TOP-003-2 VSLs for R2 - Severe VSL should just say "four" instead of "four or more" because there are only four required elements. o TOP-003-2 VSLs for R3 and R4 - the addition of the percentage range on the Lower VSL makes no sense. See comment on TOP-002-3 VSLs for R3 above.
Response: TOP-001-2, R8 – The SDT agrees and has modified the Time Horizon for R8 to only cover Operations Planning.		

Organization	Yes or No	Question 4 Comment
TOP-001-2, R8 and R9 – Please see our response to your comments in Q1. TOP-002-3, R3 – The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. There is an explanatory statement prior to the VSLs for Requirement R3 that details how the VSLs are determined in the examples provided. The SDT did add “whichever is less” in the Lower VSL and “than” in the Severe VSL. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2, R1 – The SDT disagrees. “Analyses” is the plural form of “analysis” and its use is consistent with the requirement. The SDT intended for the data specification to apply to all the analyses that the Transmission Operator must perform and not a single analysis. Otherwise, one could interpret the requirement to require a separate data specification for every analysis performed by the Transmission Operator. Definitions in the NERC Glossary are regularly used in singular or plural form in other standards. No change made. TOP-003-2 R2 – The SDT agrees and has modified the Severe VSL for R2 and R1 as well. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2 VSLs R3 and R4: The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. The SDT has added an explanatory statement prior to the VSLs for R3 and R4 that explains how the VSL is determined in the examples provided.		
Texas Reliability Entity	No	Regarding the VSL for TOP-001-2 R5, we suggest that it be based on a percent of applicable TOPs rather than number of TOPs, which would accommodate various sized entities. Regarding the VSLs for TOP-001-2 R9 and R11, we recommending adding a time duration reference relating to SOL violations, even if it is not a definite number of minutes. Referring to the VSLs for TOP-003-2 R1, there are only four elements listed, so the reference to “four or more” is nonsensical. Also, there is no difference between omitting four elements and not providing a documented specification at all. Finally, the four listed elements do not appear to have equal importance - perhaps the VSL levels should be assigned based on which elements are missing.
Response: TOP-001-2 R5 – Because VSLs using percentages must use the 5, 10, 15%, etc., scale, the SDT believes using percentages will actually escalate the VSLs for all entities more rapidly and result in a situation where the some levels are never used. In the vast		

Organization	Yes or No	Question 4 Comment
majority of situations, a Transmission Operator will have to notify, at most, its immediate neighboring Transmission Operator-s. A Transmission Operator would have to have more than 26 neighboring Transmission Operator-s before each VSL could be used. The SDT does not believe there will be any Transmission Operator with that many neighboring Transmission Operator-s. No change made. TOP-001-2 R9 & R11 – The timing requirement is implicitly contained within Facility Rating or Stability criteria. No change made. TOP-003-2 R1 – The SDT has changed "four or more" to "four". The SDT understands that failing to meet all four parts may be viewed by some as not providing any data specification. Others may not share that view and may believe that some document could be provided that does not meet any of the requirement parts. Either way the violation will be assessed at a Severe VSL. Additionally, the SDT does not believe missing any one of the four parts will contribute to a greater violation of the requirement than the other parts. See the redlined VSL in the Summary Consideration for this question to view the changes.		
E.ON Climate & Renewables	No	Considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable.
Kansas City Power & Light	No	The VSL for TOP-003-2, R5 does not recognize partially satisfying a request for data. Recommend the SDT consider a graduated set of severity levels similar to the other requirements in TOP-003-2.
Kansas City Power & Light	Negative	The VSL for TOP-003-2, R5 does not recognize partially satisfying a request for data. Recommend the SDT consider a graduated set of severity levels similar to the other requirements in TOP-003-2.
Response: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation should only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. No change made.		
ReliabilityFirst	No	For the TOP-001-2 standard, ReliabilityFirst disagrees with the VSLs for the following

Organization	Yes or No	Question 4 Comment
		reasons:1. VSLs for R3, R5 and R6 - ReliabilityFirst recommends adding the gradated language of "or X% or less of the entities whichever is less" to the VSLs (this is consistent with the language stated in the TOP-002-3 and TOP-003-2 VSLs). This is needed for smaller Transmission Operators which may have less than four other TOPs to inform. 2. Note in front of VSL 5 - ReliabilityFirst recommends removing the note in front of VSL5 since the note is contrary and is in conflict on how the VSL is set up.
Response: TOP-001-2 R3, R5, and R6: Because VSLs using percentages must use the 5, 10, 15%, etc., scale, the SDT believes using percentages will actually escalate the VSLs for all entities more rapidly and result in a situation where the some levels are never used. In the vast majority of situations, a Transmission Operator will have to notify, at most, its immediate neighboring Transmission Operators and maybe a few additional registered entities. A Transmission Operator would have to notify more than 26 entities before each VSL could be used. The SDT does not believe there will be any Transmission Operator with that many entities to notify. In this case, the SDT believes use of one, two, three, and four represents the best balance between large and small entities. No change made. TOP-001-2 R5 – The SDT has removed the note.		
American Electric Power	No	In general, the VRFs and VSLs are too severe and punitive. Because of this, as well as our objections with the redundancy of requirements in TOP-001-2, AEP cannot support the proposed VRFs and VSLs.
Response: The SDT has not made any changes because of the lack of specificity with the comments.		
Ameren	No	See comments in question 5 regarding VRF.
Response: See response to Q5.		
ACES Power Marketing Member Standards Collaborators	No	The VSLS for TOP-002-3 Requirements R1 and R2 could have more levels based on the number of days for which there is not a plan or Operational Planning Analysis.

Organization	Yes or No	Question 4 Comment
Response: The requirement was written in singular form because the SDT believes it is very important to not miss a single day. Since the requirement is for a single day, FERC VSL criteria will not allow a VSL to accumulate the number of days. No change made.		
ISO/RTO Standards Review Committee	No	TOP-001-2, R3 Moderate VSL - the word "affected' has been omitted and needs to be inserted. TOP-003-2, R1 & R2 - The use of the term 'element' in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 - The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn't this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by the ISO/RTO Standards Review Committee concerning the need to build some flexibility into the VSL for TOP-003-2 R5.
Pepco Holdings Inc	No	PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Southwest Power Pool Reliability Standards Development Team	No	TOP-001-2, R3 Moderate VSL - the word "affected' has been omitted and needs to be inserted. TOP-003-2, R1 & R2 - The use of the term 'element' in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 - The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn't this requirement have feathered VSLs such that the more data points missing the more severe the violation would

Organization	Yes or No	Question 4 Comment
		become?
Nebraska Public Power District	No	TOP-001-2, R3 Moderate VSL - the word “affected’ has been omitted and needs to be inserted. TOP-003-2, R1 & R2 - The use of the term ‘element’ in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 - The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn’t this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
Response: TOP-001-2 R3 – The SDT agrees and has modified the Moderate VSL. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2 R1 and R2 – The SDT agrees this could cause confusion and has modified the VSLs to use parts in place of elements. This is consistent with the terminology NERC filed with FERC when they eliminated sub-requirements. Thus, the VSLs apply to Parts 1.1 through 1.4 and 2.1 through 2.4. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2, R5 - The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. No change made.		
Associated Electric Cooperative, Inc.	No	TOP-001-2-R1 VSL Change: “unless such action would violate”To: “and such action would have violated” Rationale: State the issue rather than recite the requirement. TOP-001-2-R8 VSL Change: “whichever is less” To: “whichever is greater” Rationale:

Organization	Yes or No	Question 4 Comment
		Intent TOP-001-2-R10 VSL Change: “has been” To: “had been” Rationale: grammatical TOP-002-3-R1 Lower VSL: Duplicate Severe VSL wording then append “, on one day within a calendar year.” TOP-002-3-R1 Moderate VSL: Duplicate Severe VSL wording then append “, on two non-consecutive days within a calendar year.” TOP-002-3-R1 High VSL: Duplicate Severe VSL wording then append “, on three non-consecutive days or two consecutive days within a calendar year” TOP-002-3-R1 Severe VSL: Append: “, on four or more days, or three consecutive days within a calendar year.” TOP-002-3-R1 VSL changes Rationale: Eliminate zero-defect expectation TOP-002-3-R3 VSL Change: “of the NERC” To: “, whichever is greater, of the NERC” Rationale: precision and alignment with wording in TOP-01-2 R8 VSLs.

Response: TOP-001-2, R1 – The SDT agrees and has modified the VSL similar to your request. See the redlined VSL in the Summary Consideration for this question to view the changes.

TOP-001-2, R8 - The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. The SDT has added an explanatory statement prior to the VSLs for R8 that explains how the VSL is determined. No change made.

TOP-001-2, R10 – The SDT agrees and has corrected the VSL. See the redlined VSL in the Summary Consideration for this question to view the changes.

TOP-002-3, R1 – The SDT disagrees with gradating the VSLs on this requirement. The SDT believes that the requirement is of such importance that it wrote the requirement in singular form. Thus, each failure to have an OPA is a separate violation. This is also consistent with FERC VSL Guidelines. No change made.

TOP-002-3, R3 – The SDT added the missing “whichever is less” language to the Lower VSL. The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. The SDT has added an explanatory statement prior to the VSLs in R3 that explains how the VSL is determined. See the redlined version in the Summary Consideration for this question to see the

Organization	Yes or No	Question 4 Comment
changes.		
Manitoba Hydro	No	TOP-002-3 R3 VSL - The wording of the VSL is unclear. Manitoba Hydro suggests changing the wording of the VSL as follows (the severe VSL of TOP-002-3, R3 is provided as an example): 'The Transmission Operator did not notify either four or more NERC registered entities, or more than 15% of the NERC registered entities identified in the plan(s) as to their role in the plan(s).
Response: The SDT added the missing "whichever is less" language to the Lower VSL. The utilization of the "whichever is less" language has been vetted by NERC and is used in other standards. There is an explanatory statement prior to the VSLs in R3 that explains how the appropriate VSL is determined. See the redlined version in the Summary Consideration for this question to see the changes.		
United Illuminating Company	No	TOP-003 R5 has only a severe VSL. This seems unequitable to the data providors who are responsible for tens of thousands of data points, some redundant. Especially since State Estimators are designed to estimate for bad or missing data. UI disagrees with vsl for R5 which is severe only. UI is concerned that failing to provide a single data point for a partial period would result in a severe violation reagardless of all the other data being transmitted. UI notes that with in TOP-001 (R6 and R8) and TOP-02 R3 the SDT managed to create VSL's that allowed for percentage measure or quantity measure. A similar approch should be done with TOP-003 R5. Failure to transmit a single point of data will not result in a cascade or directly affect the electrical stae of the BES.
Response: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT		

Organization	Yes or No	Question 4 Comment
believes a single Severe VSL is appropriate. Writing VSLs based on the number of data points provided would further complicate compliance enforcement actions for the responsible entity by requiring them to provide evidence of the number of data points they are required to provide to demonstrate sample size is not practical. No change made.		
South Carolina Electric and Gas	No	
Response: Without a specific comment, the SDT is unable to respond.		
Beaches Energy Services	Negative	It would seem that the VSL for TOP-001 R5 ought to be binary, not informing any TOP of a potential Adverse Reliability Impact seems a Severe violation. It does pose the question, which TOPs? All of them in the interconnect? Only neighboring TOPs? Only TOP's in the RC area? TOP-003 VRFs - there should not be an inconsistency between R1, R2 and R3 for creation and distribution of data specifications being Low VRF, but supplying the data required is a Medium. They should be the same, e.g., if a RC, BA or TOP doesn't tell the other entities what data is required, how can that entity know what to supply? VSLs for R1 and R2, "required element" as used in the VSLs should be replaced with "specifications" to coincide with the term used in the requirement. VSL for R5 should not be binary. It is inconsistent with other requirements. E.g., If in R4, a BA or TOP did not distribute to 3 entities, and therefore did not receive any data from those 3 entities, then, that is a low VRF and High VSL to the BA for missing all of the data from 3 entities. However, in R5 if an entity misses one piece of data from that entity it is a Medium VRF and a Severe VSL. This is inconsistent.
Response: TOP-001, R5 – The SDT disagrees that the VSL ought to be binary. Failure to notify one Transmission Operator of an Adverse Reliability Impact is not as Severe as failing to notify the Reliability Coordinator. Failure to notify the Reliability Coordinator is a Severe VSL. If the Reliability Coordinator knows, then the Reliability Coordinator will ensure the Adverse Reliability Impact is addressed. The answer to the question of which Transmission Operators is found within the requirement. It is the Transmission Operators that are "known or expected" to be affected by the Adverse Reliability Impact. That could be immediate neighbors or		

Organization	Yes or No	Question 4 Comment
broader if the Transmission Operator's operations are "known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas". No change made. TOP-003 – The SDT views development and communication of a data specification as an enabling requirement for ensuring the Transmission Operator and Balancing Authority have the necessary data. Actual supply of the data is what is most important in this requirement. The VRFs reflect this relative importance. No change made. The SDT agrees that "elements" in the VSLs for Requirements R1 and R2 is not the correct word and has modified the VSLs to use parts in place of elements. This is consistent with the terminology NERC filed with FERC when they eliminated sub-requirements. See the redlined version in the Summary Consideration for this question to see the changes. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. Writing VSLs based on the number of data points provided would further complicate compliance enforcement actions for the responsible entity by requiring them to provide evidence of the number of data points they are required to provide to demonstrate sample size and is not practical. No change made.		
California ISO	Negative	The VSL table states the following as Severe for TOP-001 R9: The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria. We cannot agree with this wording until the meaning of "continuous" is better defined.
Response: The language quoted in the comment is not from the most recent VSL in TOP-001-2, Requirement R9. For example, the VSL mentions nothing about 30 minutes. The SDT intended the literal meaning of continuous. Thus, the duration would start over if the Transmission Operator managed to temporarily bring the operation of the SOL back within the limit. No change made.		
Florida Municipal Power Agency	Negative	TOP-001-2 R5 and R9 VRFs should be High, especially R9 It would seem that the VSL for R5 ought to be binary, not informing any TOP of a potential Adverse Reliability Impact seems a Severe violation. It does pose the question,

Organization	Yes or No	Question 4 Comment
		which TOPs? All of them in the interconnect? Only neighboring TOPs? Only TOP's in the RC area? The VSL for R8 for Lower, Moderate and High ought to be reworded to avoid the ambiguous reference and make sure that IROLs are always Severe, e.g., (one, two, or three) SOLs that are not IROLS or more than (X% to Y%) .... TOP-002-3 VRF's and VSL's look good TOP-003-2 VRFs - there should not be an inconsistency between R1, R2 and R3 for creation and distribution of data specifications being Low VRF, but supplying the data required is a Medium. They should be the same, e.g., if a RC, BA or TOP doesn't tell the other entities what data is required, how can that entity know what to supply? VSLs for R1 and R2, "required element" as used in the VSLs should be replaced with "specifications" to coincide with the term used in the requirement VSL for R5 should not be binary. It is inconsistent with other requirements. E.g., If in R4, a BA or TOP did not distribute to 3 entities, and therefore did not receive any data from those 3 entities, then, that is a low VRF and High VSL to the BA for missing all of the data from 3 entities. However, in R5 if an entity misses one piece of data fro that entity it is a Medium VRF and a Severe VSL. This is inconsistent.
City of Vero Beach	Negative	TOP-001 R5 and R9 VRFs should be High, especially R9 It would seem that the VSL for R5 ought to be binary, not informing any TOP of a potential Adverse Reliability Impact seems a Severe violation. It does pose the question, which TOPs? All of them in the interconnect? Only neighboring TOPs? Only TOP's in the RC area?

Organization	Yes or No	Question 4 Comment
		The VSL for R8 for Lower, Moderate and High ought to be reworded to avoid the ambiguous reference and make sure that IROLs are always Severe, e.g., (one, two, or three) SOLs that are not IROLS or more than (X% to Y%) .... TOP-003 VRFs - there should not be an inconsistency between R1, R2 and R3 for creation and distribution of data specifications being Low VRF, but supplying the data required is a Medium. They should be the same, e.g., if a RC, BA or TOP doesn't tell the other entities what data is required, how can that entity know what to supply? VSLs for R1 and R2, "required element" as used in the VSLs should be replaced with "specifications" to coincide with the term used in the requirement VSL for R5 should not be binary. It is inconsistent with other requirements. E.g., If in R4, a BA or TOP did not distribute to 3 entities, and therefore did not receive any data from those 3 entities, then, that is a low VRF and High VSL to the BA for missing all of the data from 3 entities. However, in R5 if an entity misses one piece of data from that entity it is a Medium VRF and a Severe VSL. This is inconsistent.

Response: TOP-001, R5 VRF – The SDT disagrees. There is a similar requirement (Requirement R5) in proposed IRO-014-2 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities: TOP-001-2 for Transmission Operators and IRO-014-2 for Reliability Coordinators. The assignment of the Medium VRF was made based on the premise that failure to coordinate activities, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to coordinate activities. While the SDT agrees that, under some circumstances, it is possible that a failure to coordinate activities may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to coordinate would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to coordinate activities, it would still be expected to handle the situation if it occurred.

TOP-001-R9, VRF – The SDT disagrees that the VRF should be High for an SOL. SOLs do not have the same level of importance as an IROL. No change made.

Organization	Yes or No	Question 4 Comment
TOP-001, R5 VSL – The SDT disagrees that the VSL ought to be binary. Failure to notify one Transmission Operator of an Adverse Reliability Impact is not as Severe as failing to notify the Reliability Coordinator. Failure to notify the Reliability Coordinator is a Severe VSL. If the Reliability Coordinator knows, then the Reliability Coordinator will ensure the Adverse Reliability Impact is addressed. The answer to the question of which Transmission Operators is found within the requirement. It is the Transmission Operators that are "known or expected" to be affected by the Adverse Reliability Impact. That could be immediate neighbors or broader if the Transmission Operator's operations are "known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas". No change made. TOP-001-2, R8 – IROLs are not considered in this requirement. It only pertains to selected, identified SOLs which are not IROLs. No change made. To further clarify the VSLs, a "boiler plate" explanation for how to select the VSL has been added above the VSLs. TOP-003 – The SDT views development and communication of a data specification as an enabling requirement for ensuring the Transmission Operator and Balancing Authority have the necessary data. Actual supply of the data is what is most important in this requirement. The VRFs reflect this relative importance. No change made. TOP-003, R1 and R2 - The SDT agrees that "elements" in the VSLs for Requirements R1 and R2 is not the correct word and has modified the VSLs to use parts in place of elements. This is consistent with the terminology NERC filed with FERC when they eliminated sub-requirements. See the redlined versions in the Summary Consideration for this question to view the changes. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. Writing VSLs based on the number of data points provided would further compliance enforcement actions for the responsible entity by requiring them to provide evidence of the number of data points they are required to provide to demonstrate sample size and is not practical. No change made.		
CPS Energy	Negative	Quality Review of VRF's needed.
Response: A quality review of all VRF's is part of the standard review cycle for all projects.		

Organization	Yes or No	Question 4 Comment
Intellibind	Negative	Data retention requirements are not consistent with other standards that only require maintaining logs and voice recordings for 90 days. This adds confusion to compliance recordkeeping where some records are purged every 90 days, but that records of certain topic must be maintainted for longer periods. Retention of data should be done on an identified amount of days (eg. 30, 60, 90) as apposed to "consecutive months" since computer systems primarily use a count of days, and do not necessarily distigiush a calandar month for purging records. As stated the retention period will add addtional adminsitratve overhead and expense to ensuring compliance to these requirements.
Response: The general language of the data section is provided by NERC staff. The SDT found only one instance of calendar month in the standards. It stated that voice recordings shall be retained for three calendar months. The SDT changed that reference to 90 calendar days.		
Liberty Electric Power	Negative	I do not understand why a TO or BA who fails to send a data request to a generator would receive a "Low" VSL while that same generator would receive a "severe" VSL for not satisfying all the requirements of the data request.
Response: The SDT views Requirements R1 – R4 as enabling requirements. The purpose of TOP-003-2 is to make sure the Transmission Operator and Balancing Authority have the data necessary for fulfilling their functional obligations. Thus, the real crux of the standard is to supply data. Everything else is simply administrative to enable the sharing of that data. If the generator owner or generator operator does not receive a data specification, they have no obligation under the standards to supply data and cannot be held in violation of the Requirement R5. Thus, no situation could ever exist where a Balancing Authority or Transmission Operator is held in violation of Requirements R3 or R4 for failing to send the data specification to a generator owner or generator operator and then that same generation owner or generation operator is held in violation of Requirement R5. No change made.		
Bonneville Power Administration	Negative	BPA is voting "No" for VSLs/VRFs for R8 of TOP-001-2, R3 of TOP-002-3, and R3/R4 of TOP-003-2 because they are written in a confusing manner. BPA recommends using 1, 2, 3, or 4 SOLs instead of trying to including things like "more than 10%, but less than 15%", particularly since the requirement is to take the lesser or that or the 1, 2, 3, or 4 SOLs.
Response: The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. There was an explanatory statement prior to the VSLs in some of these requirements that explains how the appropriate VSL is determined. It was		

Organization	Yes or No	Question 4 Comment
missing before others. The explanatory statement has been added where appropriate.		
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	Ingleside Cogeneration LP believes that the requirements applicable to a GO/GOP carry VRFs, VSLs, and Time Horizons consistent with those assigned to similar requirements.
NIPSCO	Yes	None at this time
Southwest Power Pool Regional Entity	Yes	
FirstEnergy	Yes	
Imperial Irrigation District (IID)	Yes	
Dominion	Yes	
FMPP	Yes	
Muscatine Power and Water	Yes	
Independent Electricity System Operator	Yes	
Dairyland Power Cooperative	Yes	
Omaha Publc Power District	Yes	
US Bureau of Reclamation	Yes	
Response: Thank you for your support.		

5. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: The majority of comments received for this question were re-statements of earlier comments or simple requests for clarification. No changes were made to any requirements due solely to comments in this question.

Organization	Yes or No	Question 5 Comment
Potomac Electric Power Co.	Abstain	Pepco Holdings Inc. supports the comments offered by EEI.
Response: EEI did not supply comments to this posting.		
Great River Energy	Affirmative	Comments submitted with the MRO NSRF
Minnkota Power Coop. Inc.	Negative	Please see comments submitted by the MRO NSRF.
Response: See the responses to MRO NSRF comments in Q1 – Q4.		
SERC Reliability Corporation	Affirmative	Don't forget to synch the definition of Directive with COM-002.
Response: The SDT is in contact with, and coordinating as necessary, with the SDT that is working on COM-002.		
Florida Municipal Power Pool	Affirmative	Implementation Comments submitted. Added here incase they did not go through. Comments for Project 2007-03 Real-Time Transmission Operations The changes to the TOP Standards are a great improvement over the existing Standards; however, I think because they are so much better than the existing Standards that they should be implemented as soon as possible. I think one year is enough time to make the necessary changes to processes, procedures and documentation. Even more important than the implementation of the new Standards is the deletion of the existing Standards as soon as possible. Some of the existing Requirements are worthless and unenforceable. The SDT has determined that some of the existing

Organization	Yes or No	Question 5 Comment
		Requirements are replaced by new requirements and they will need to be enforceable until the new Requirements are enforceable. However, the SDT has identified some Requirements that are either no longer necessary or covered by existing Requirements or the Functional Model (see mapping document excerpts below): o PER-001-0 R1 o TOP-001-1 R1 o TOP-002-2 R2 o TOP-002-2 R7 o TOP-002-2 R8 o TOP-002-2 R18 o TOP-002-2 R19 Deleting these Requirements does not need to have an implementation period. They can be deleted as soon as approved by FERC with no waiting. TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it never should have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! Also the SDT has identified some Requirements that apply to the Balancing Authority that are either no longer necessary (or even NEVER should have been applicable) or covered by existing Requirements or the Functional Model (see mapping document excerpts below): o TOP-002-2 R1 o TOP-002-2 R5 o TOP-002-2 R6 o TOP-002-2 R10 The SDT states for TOP-002-2 R10: “The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority.” Obvious wrong Requirements like TOP-002-2 R10 should be deleted ASAP. They are a compliance conundrum, and open to compliance fines! From the Mapping Document: PER-001-0 R1 is deleted because “In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator’s authority to issue directives arises out of the Commission’s approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.” TOP-001-1 R1 is deleted because “This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn’t alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible

Organization	Yes or No	Question 5 Comment
		entity. These needed actions required for reliability of the bulk power system have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement." TOP-002-2 R1 is deleted for the Balancing Authority because "The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and must take action per approved EOP-002-2.1, Requirement R6 and thus the Balancing Authority part of this sentence can be deleted. Second sentence - Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities as per their certification as NERC registered entities. " TOP-002-2 R2 is deleted because "The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted. " TOP-002-2 R5 is deleted for the Balancing Authority because "The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model." TOP-002-2 R6 is deleted for the Balancing Authority because "The part of this requirement dealing with the Balancing Authority is replaced by approved BAL-002- 0 and proposed BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of

Organization	Yes or No	Question 5 Comment
		operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. " TOP-002-2 R7 is deleted because "The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-1, Requirement R2 and therefore this requirement is redundant and can be deleted as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority!" TOP-002-2 R8 is deleted because "The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted as all elements of the requirement are now covered in other standards. Voltage and reactive power balance are the responsibility of the Transmission Operator (not the Balancing Authority) and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority!!" TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it should never have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! TOP-002-2 R10 is deleted for the Balancing Authority because "The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority." TOP-002-2 R18 is deleted because "This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. " To make matters worse this Requirement is the tier 1 Requirements for actively monitored Requirements for 2012! Which means NERC views this as an important Requirement to reliability. But I agree with the SDT that this Requirement adds NO reliability benefit. TOP-002-2 R19 is deleted because "This is part of an entity's certification and is no longer required in standards. "

Organization	Yes or No	Question 5 Comment
Response: The SDT appreciates your concerns. However, no change is being made due to the following reasons: 1. The requirements being cited are in service today and are being 'followed' by registered entities with minimal problems. The main difference in this project from today is the formalization of some of the requirements particularly the data specification. 2. This is the only comment received on this issue. Other entities are apparently okay with the status quo. **3.** Setting up an implementation plan with the suggestions above would make for a logistical nightmare with no reliability benefit. **4.** The SDT has shortened the effective date to 12 months for all requirements except the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
MEAG Power	Affirmative	MEAG Power supports the comments of Austin Energy.
Response: Austin Energy did not supply any comments to this posting.		
Portland General Electric Co.	Affirmative	PGE agrees with the WECC Position paper on Real-Time Operations.
Response: Without specific comments to this posting the SDT is unable to respond.		
Illinois Municipal Electric Agency		Illinois Municipal Electric Agency appreciates SDT efforts to develop a sixth draft for this proposed Reliability Standards development. While we realize the SDT will never be able to resolve all concerns, it appears from our own review and our review of other entity comments that additional revisions are needed to achieve a level of quality that will minimize difficulties complying with these Reliability Standards.
Baltimore Gas & Electric Company, Constellation Energy Commodities Group	Affirmative	We are voting affirmatively because we support the improvements achieved by the drafting team work so far. However, we raised remaining concerns with the standard proposal on the comment form submitted on behalf of CCG, CECD and CPG. We expect the drafting team to continue to make clarifying changes until the end of this stakeholder process. The greater the clarity in the final product, the less risk of contradictory perspectives on compliance.

Organization	Yes or No	Question 5 Comment
Response: The SDT will continue to work to refine the standards until the end of the stakeholder process.		
Santee Cooper	Negative	"Internal area reliability" needs to be clarified.
Response: Requirement R8 was modified to replace the phrase "its internal area reliability" with "reliability internal to its Transmission Operator Area". **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Fort Pierce Utilities Authority	Negative	Please see the joint comments submitted by Florida Municipal Power Agency (FMPA) filed through the formal comment process.
Response: See response to FMPA comments in Q1 – Q4.		
Consolidated Edison Co. of NY, Inc.		Comments: TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for "Reliability Directive" changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an "across the board" usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts." It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts

Organization	Yes or No	Question 5 Comment
		compliance to COM-002.
Orange and Rockland Utilities, Inc.		Comments: TOP-001-2 is referencing a NERC definition for “Reliability Directive” which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of “Reliability Directive” would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board” usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.” It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team as well.		
Georgia System Operations		GSOC believes that all 3 standards should be voted on together in one vote. They are too inter-related. One or two of these should not be approved if one of them is not approved.
Response: The purpose of separating the votes at this stage was to provide additional feedback to the SDT. The three standards will be filed together once all 3 have been approved by the industry.		
Texas Reliability Entity		Referring to the posted “Issues Database,” under Order 693 Â¶ 1604/1608, the red-lined language is not actually in the referenced requirement. Does the drafting team

Organization	Yes or No	Question 5 Comment
		contend that the proposed requirements satisfy this FERC directive? Referring to the posted “Issues Database,” under Order 693 Â¶ 1636 (TOP-004), this document suggests that a 30-minute limit is contained in the requirements, but that limit is not in the language that is now posted. Does the drafting team contend that the proposed requirements satisfy this FERC directive? In general, NERC needs to make sure the Issues Database is consistent with the latest draft of the requirements. The VRF/VSL Assignment Document needs to be cleaned up. There are numerous references to incorrect requirement numbers. On page 3, TOP-001-2 Requirement R3 is struck from the list of “High” VRFs, but it is assigned a high VRF in the posted standard. Also, the title of TOP-001-2 is stated incorrectly in this document (at the beginning).
Response: 1604 - The SDT agrees that the posted language was not updated in the issues database to reflect the latest version of the standard. However, the context hasn’t changed and the SDT does believe that the suggested requirement addresses the directive. The issues database language has been cleaned up appropriately. No other change made. 1636 – The issues database language was not properly updated when the requirement was changed from a 30 minute perspective to a limits perspective. However, the context hasn’t changed and the SDT does believe that the suggested requirement addresses the directive. The issues database language has been cleaned up appropriately. No other change made. The SDT has reviewed the VRF/VSL document and made changes as appropriate. The SDT does not understand the comment. The posted requirement is assigned a high VRF. The VRF/VSL document states that Requirement R3 has been assigned a high VRF. There does not appear to be a discrepancy. No change made. The title has been corrected in the VRF/VSL document.		
American Transmission Company, LLC		ATC feels this project has diminished a good base of existing standards, and introduced ambiguity, and vagueness. Additionally, we feel certain key aspects of the current standards were removed for example, “Clear, decision making authority” from System Operators, and the need for “Uniform Line Identifiers”, which is not in

Organization	Yes or No	Question 5 Comment
		the interest of Reliability.
Response: The SDT has provided reasons for deleting the two phrases referenced above in the mapping document accompanying this posting. To date, the SDT has seen no justifications for restoring the cited phrases. No change made.		
SERC OC Standards Review Group		Data retention requirements for TOP-001-2. TOP-002-3 and TOP-0003-2 need to align with the expectations of the compliance entity."The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Owensboro Municipal Utilities	Negative	Please refer to SERC Operating Committee Comments.
Entergy, Entergy Services, Inc.	Negative	o Comments submitted - see SERC OC Standards Review Group comments.
Response: The data retention requirements for all 3 standards follow the established guidelines and were reviewed as part of the quality review process prior to posting. No change made.		
GTC		Demonstrating providing all data specifications for real time operations horizon is very prescriptive in nature and could have unanticipated "compliance documentation" consequences when data or the transfer method is unavailable (e.g., when an RTU goes down).
Response: Demonstrating the need would be an onerous task with no reliability benefit. The Transmission Operator and Balancing Authority are constrained as to what they can request by the language in the requirements. They can only ask for what is needed to support their assigned tasks. No change made.		
FirstEnergy		FE has the following comments and suggestions:1. In the mapping document, it shows that PRC-001-1 R2 will be replaced by the new TOP-003-2 R5. However, we do not see a new version of PRC-001-2 posted. Also, the implementation plan makes no reference to PRC-001.

Organization	Yes or No	Question 5 Comment
		2. The mapping document does not seem to be referencing the correct version of TOP-005 (should be Version 2a). Also, the mapping document is not referencing the correct requirement for TOP-006-1 R4 (the RC should not be shown as applicable).
Response: The PRC standard was inadvertently left out of this posting but has been provided as part of the next posting. The Implementation Plan has been updated as well. The correct reference should be TOP-005-2a and the mapping document has been changed as necessary to reflect this. Requirement R4 has been corrected.		
NV Energy		In the re-draft of these three standards, TOP-001, -002, and -003, we seem to have lost the concept of Planned Outage Coordination for BES facilities (a whole Standard was devoted to the process). In viewing the mapping document, it is stated that the requirements for such outage coordination that used to reside in TOP-003-1 are now replaced by R1 and R2 of TOP-003-2. If this is the case, then all of the activities of outage coordination are to be encapsulated in the clause "documented specification for the data necessary for it to perform its required Operational Planning Analyses..." While it may be covered in this extremely broad clause, the SDT nevertheless gave prominence to the coordination of telemetry outages within a specific requirement R6 of TOP-001-2. If telemetry outages have a separate requirement, then shouldn't planned outage coordination of BES facilities rise to the level of importance that would merit its own requirement?
Response: Since telemetry outages might take out the very mechanism relied upon for the transfer of data in TOP-003-2, the SDT believed that a separate requirement was necessary for such outages. Also, telemetry is part of infrastructure and not a type of data so it is handled separately. No change made.		
PacifiCorp		PacifiCorp would like to express their appreciation to the SDT for their efforts. This consolidation effort has resulted in a more streamlined approach to this set of interrelated NERC Reliability Standards. PacifiCorp would recommend that NERC

Organization	Yes or No	Question 5 Comment
		consider other sets of standards for which such a consolidation effort would be mutually beneficial to NERC and stakeholders, from both a compliance and administrative standpoint.
Response: Thank you for your support.		
Dominion		Page 1 and Page 15 of the Violation Risk Factor and Violation Severity Level Assignments document, titles reads; Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-2, TOP-003-2:, Dominion suggests changing TOP-002-2 to TOP-002-3.
Response: The suggested correction has been made.		
Pepco Holdings Inc		PHI supports the comments provided by the ISO/RTO Standards Review Committee.
ISO/RTO Standards Review Committee		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Midwest ISO, Inc.	Affirmative	Please See SRC Comments Submitted
New Brunswick System Operator	Negative	Please see comments submitted by the NPCC Reliability Standards Committee and IRC/SRC
Southwest Power Pool Reliability Standards Development Team		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
City Utilities of Springfield, Missouri	Negative	City Utilities of Springfield, Missouri supports the comments of SPP.

Organization	Yes or No	Question 5 Comment
Empire District Electric Co.	Negative	EDE agrees with the comments provided by SPP RTO
ISO New England Inc.		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Nebraska Public Power District		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Constellation Energy		The definition of Reliability Directive is contained in COM-002-3 which has not been approved at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved or change? Since the two projects appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently.
Northeast Power Coordinating Council		TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard Section on page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for "Reliability Directive" changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an "across the board" usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is

Organization	Yes or No	Question 5 Comment
		necessary to address an Emergency or Adverse Reliability Impacts." It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team as well.		
Southwest Power Pool Regional Entity		The standards being proposed are not sufficient to replace the requirements of the 9 standards being retired by this project. The requirements listed below are not covered by the new standards. TOP-001-1 R5. New requirement (TOP-001-2 R11) does not cover "take actions to avoid when possible or mitigate the emergency." Pre-emptive action is an important part of preventing cascading outages. The proposed TOP-001-2 R11 only deals with real time violations. The SDT is relying upon IRO-001-3 being approved in order to retire some of these requirements; however, this has not yet been passed by industry. TOP-002-2R1. If conditions change on the current day, where in the proposed standards is a new operating plan required to prepare for the next contingency or identify new SOLs? R6. Which of the proposed standards obligate the TOP to continuously plan for the next N-1 event? R13. MOD-024 and MOD-025 (which would replace this requirement) were not approved by FERC in the initial set of standards. A replacement standard MOD-025-2 has been posted for comment, but has not had an initial ballot. TOP-004-2R1. The proposed TOP-001-2, R7 and R9, only requires IROLs and certain SOLs be respected. The requirement being retired applied to all SOLs. This reduces BES reliability. R4. This covers cases where no Operational Planning Assessment is available to

Organization	Yes or No	Question 5 Comment
		ensure the system is in a safe state. The proposed TOP-002-3 does not include any requirement about when a new study is needed. TOP-006-2R5., R6., R7. The SDT is relying on the certification process to justify the retirement of these requirements. However, the Certification Process only looks at approved applicable Reliability Standards. If these are retired, these will no longer be reviewed by the Certification Team. TOP-008-1R2. The current language in TOP-008-1, R2 of "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" is different than the proposed language of TOP-001-2, R7 and R9 "shall not operate outside the IROL (or SOL)". We recommend incorporating the "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" into TOP-001-2 R7. PER-001-0R1. The existing requirement specifically places the responsibility on the personnel on shift not on the senior management. This does not appear to be covered by any other requirement. PRC-001-1 R2. The obligation to take corrective actions for protection relay or equipment failures is not covered by the proposed TOP-003-2 standard.

Response: TOP-001-1, R5: For anticipated conditions, the proposed TOP-002-3, Requirements R2 and R3 require the TOP to "develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1." The proposed TOP-001-2, Requirement R11 requires each Transmission Operator to "act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8." When the exceedance anticipated in the assessment of the Operational Planning Analysis in proposed TOP-002-3, Requirement R1 becomes an actual exceedance in Real-time operations, the plan that the Transmission Operator developed per proposed TOP-002-3, Requirements R2 and R3 is to be implemented. Thus, the possible appropriate action to take, according to proposed TOP-001-2, Requirement R11 is to "act or direct others to act" in accordance with the plan that addresses the exceedance. Of course, this is all accomplished in accordance with the Reliability Coordinator as per approved IRO-008-1. No change made.

IRO-001-3: The SDT understands the timing and coordination issues involved with IRO-001-3 and is working closely with Project 2006-

Organization	Yes or No	Question 5 Comment
06 in this regard. TOP-002-2, R1: TOP-002-3 uses Operational Planning Analysis which includes contingency planning. The SDT believes that this will incorporate most of the situations that will occur in real-time. If something comes along that wasn't in the plan the language doesn't preclude an entity running a new analysis. No change made. TOP-002-2, R6: Requirement R6 does not mandate continuous planning. The mapping document shows how the SDT is proposing replacing this requirement. No change made. TOP-002-2, R13: The SDT is aware of the coordination issues involved and will take appropriate actions when, and if, required to make certain that there is no reliability gap created. TOP-004-2, R1: The SDT has provided the reasoning for the handling of SOLs repeatedly over the life of the project. The majority of the industry is on board with these changes as seen in provided comments. The SDT believes that the suggested changes do not adversely affect reliability. No change made. TOP-004-2, R4: The old Requirement R4 does not say anything about a new study. The SDT believes that the mapping shown for this requirement clearly covers the situation. No change made. TOP-006-2, R5: The certification process is not necessarily restricted to existing requirements. In deleting requirements based on certification, the SDT is responding to guidance received from NERC staff which has instructed SDTs to delete requirements that can and will be shown as initial capabilities during certification. In addition, where such requirements have been deleted in this project, the mapping document always shows where other remaining requirements would be violated if the core certification requirements aren't met and maintained. Therefore, no reliability gap is created. No change made. TOP-008-1, R2: Any pre-emptive actions for IROLs are the responsibility of the Reliability Coordinator as per the approved IRO standards. No change made. PER-001-0, R1: The SDT proposed in the first posting of this project that such a requirement is no longer needed in standards as cited in the posted mapping document. No change made. PRC-001-1, R2: There is no wording here for corrective actions. That is covered in PRC-004-2a, Requirement R2. No change made.		
South Carolina Electric and Gas		There is a mistake in the mapping document for TOP-001-2 R11 as the language doesn't match the language in the Standard. There is additional language in the mapping document that states "within 30 minutes," which the standard does not,

Organization	Yes or No	Question 5 Comment
		and should not say. This occurs on page 36 for the mapping of current TOP-007 R2 to proposed TOP-001-2 R11. Additonally, SCE&G believes that it would be erroneous to remove TOP-004 R5 on the basis of the functional model. The functional model for the TOP stipulates that the TOP "is responsible for the real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably." If a situation were to arise where there was not sufficient time to contact the RC or if the RC was taking action that would put the TOP in jeopardy, SCE&G believes that the TOP has the right to separate from the Interconnection to protect the reliability of its system as is spelled out in current standard TOP-005 R5.
Response: The mapping document language was not properly updated when the requirement was changed from a 30 minute perspective to a limits perspective. However, the context hasn't changed and the SDT does believe that the suggested requirement addresses the issue. The mapping document has been cleaned up appropriately. No other change made. The SDT is not basing the deletion of this requirement solely on the Functional Model. Good operating practice would dictate such a deletion as well. The SDT believes that separation must be under the control of the Reliability Coordinator. No change made.		
Xcel Energy		There is reference in each draft standard to deleting some requirements from PRC-001 but those proposed changes are not show in any proposed drafts or implementation plans (only 1 PRC-001 requirement is listed in the implementation plan).
Response: The PRC standard was inadvertently left out of this posting but has been provided as part of the next posting. The Implementation Plan has been updated as well.		
Western Area Power Administration		TOP 1 and 2 as written are generally acceptable. TOP 3 opens doors for manipulation.

Organization	Yes or No	Question 5 Comment
Response: Without specific comments, the SDT is unable to respond.		
The Valley Group, a Nexans Company		TOP-004-2 R4:If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits, as determined by System Operating Limits or real-time measurements, have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits (SOLs or Real-Time Limits) within 30 minutes. TOP-006-2 R1.2Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources, as determined with SOLs or Real-Time Calculated limits, available for use. TOP-006-2 R2:Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real time operating capacity, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. TOP-008-1 R2:Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall operate the Bulk Electric System to the actual real-time limits (if available) or the most limiting derived parameter. TOP-008-1 R3:The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. The Transmission Operator shall review the real time status and capacity of transmission facility prior to disconnecting, if applicable. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

Organization	Yes or No	Question 5 Comment
		TOP-008-1 R4:The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation. If applicable, and prior to immediate mitigation, the Transmission Operator shall review real time status and capacity of the equipment, and based on those, made necessary adjustments.
Response: The SDT does not understand the comment which appears to be a cut and paste of some existing requirements with no suggestions. No change made.		
Ameren		We highly recommend that you do not lump requirements that include SOL with IROL. IROLs by definition should have VRFs higher than SOL. So it is not possible to properly assign the VRF consistent with the NERC VRF/VSL Guideline documents. We would suggest that the SDT could review what the FAC-003 SDT has done and then provide separate Requirements when there are known and expected VRF differences for different elements covered by a combined Requirement.
Response: In this case, the SOLs being referenced are specifically, and explicitly, identified as important to a local area. This does not equate an SOL to an IROL but does imply common handling of the VRF. No change made.		
BGE		We realize that SDT for Project 2006-06 is responsible for defining Reliability Directive; however, we would like to reiterate our position that the definition must capture the identification concept that is reflected in Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. Additionally, the currently proposed definition of Reliability Directive is also contained in COM-002-3 and IRO-001-3 which have not been approved at this time. What happens if the TOP standards are approved and the COM and IRO standards are subsequently not approved or change? The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. Since the two projects

Organization	Yes or No	Question 5 Comment
		appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently. We are voting affirmatively because we support the improvements achieved by the drafting team work so far. However, we raised remaining concerns with the standard proposal on the comment form submitted on behalf of BGE. We expect the drafting team to continue to make clarifying changes until the end of this stakeholder process. The greater the clarity in the final product, the less risk of contradictory perspectives on compliance.
Response: Your suggestion has been forwarded to Project 2006-06. The SDT is coordinating activities with Project 2006-06 in this regard. The SDT will continue to work to refine the standards until the end of the stakeholder process.		

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Real-time Transmission Operations – Project 2007-03

The Real-time Transmission Operations Drafting Team thanks all commenters who submitted comments on the 7th draft and successive ballot of the standards for Real-time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from March 22, 2012 through April 20, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 41 sets of comments, including comments from approximately 143 different people from approximately 111 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The SDT made several clarifying changes to the project standards as a result of industry comments:

- TOP-001-2: deleted Operations Planning from the Time Horizons for Requirement R1
- TOP-002-3: changed to ninety calendar days in Data Retention
- TOP-003-2: added a reference to analysis functions to Requirement R2, Part 2.1 for consistency with the main requirement
- VSLs for TOP-001-2: added clarifying language to Requirements R3, R5, and R6 for consistency with Requirement R8

The changes made are clarifying in nature and do not change the content or intent of the requirements. Therefore, the SDT is requesting that the project be moved to a recirculation ballot.

No new minority opinions arose in this round of comments.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	David Kiguel	Hydro One Networks Inc.	NPCC	1
9.	Michael Lombardi	Northeast Utilities	NPCC	1
10.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Bruce Metruck	New York Power Authority	NPCC	6
12.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
13.	Robert Pellegrini	The United Illuminating Company	NPCC	1
14.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
15.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
16.	Brian Robinson	Utility Services	NPCC	8
17.	Saurabh Saksena	National Grid	NPCC	1
18.	Michael Schiavone	National Grid	NPCC	1
19.	Wayne Sipperly	New York Power Authority	NPCC	5
20.	Tina Teng	Independent Electricity System Operator	NPCC	2
21.	Donald Weaver	New Brunswick System Operator	NPCC	2
22.	Ben Wu	Orange and Rockland Utilities	NPCC	1
23.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Ron Sporseen	PNGC Group Comments	X		X	X				X		

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe Jarvis	Blachly-Lane Electric Cooperative	WECC	3
2.	Dave Markham	Central Electric Cooperative	WECC	3
3.	Dave Hagen	Clearwater Power Company	WECC	3
4.	Roman Gillen	Consumers Power Inc.	WECC	1, 3
5.	Roger Meader	Coos-Curry Electric Cooperative	WECC	3
6.	Dave Sabala	Douglas Electric Cooperative	WECC	3
7.	Bryan Case	Fall River Electric Cooperative	WECC	3
8.	Ray Ellis	Lincoln Electric Cooperative	WECC	3
9.	Annie Terracciano	Norther Lights Inc.	WECC	3
10.	Aleka Scott	PNGC	WECC	4
11.	Heber Carpenter	Raft River Rural Electric Cooperative	WECC	3
12.	Steve Eldrige	Umatilla Electric Cooperative	WECC	1, 3
13.	Marc Farmer	West Oregon Electric Cooperative	WECC	4
14.	Margaret Ryan	PNGC	WECC	8

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	John Allen	City Utilities of Springfield	SPP	1, 4									
2.	Jake Burger	Nebraska Public Power District	MRO	1, 3, 5									
3.	Doug Callison	Grand River Dam Authority	SPP	1, 3, 5									
4.	Gary Cox	Southwestern Power Adminstration	SPP	1, 5									
5.	David Dieterich	Omaha Public Power District	MRO	1, 3, 5									
6.	Kim Donghyeon	Burns & McDonald	NA - Not Applicable	NA									
7.	Allan George	Sunflower Electric Power Corporation	SPP	1									
8.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6									
9.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6									
10.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6									
11.	Paul Lampe	City of Independence, Power & LIght Department	SPP	3									
12.	Julie Lux	Westar Energy	SPP	1, 3, 5, 6									
13.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5									
14.	Kyle McMenamin	Xcel Energy	SPP	1, 3, 5, 6									
15.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5									
16.	Terry Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5									
17.	Randy Root	Grand River Dam Authority	SPP	1, 3, 5									
18.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5									
19.	Sean Simpson	Board of Public Utilities, City of McPherson	SPP	1, 3, 5									
20.	Angela Summer	Southwestern Power Administration	SPP	1, 5									
21.	Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6									
4.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Alfonso Juarez III	IID	WECC	1, 3, 4, 5, 6									
2.	Joel Fugett	IID	WECC	1, 3, 4, 5, 6									
5.	Group	Connie Lowe	Dominion	X		X		X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Louis Slade		RFC	5									
2.	Mike Garton		MRO	5									
3.	Michael Crowley		SERC	1, 3, 5, 6									
6.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL/NSP	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	3, 4, 5, 1
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 4
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	THERESA ALLARD	MPC	MRO	1, 3, 5, 6

7.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

8.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Jake Burger	Nebraska Public Power District	MRO	1, 3, 5
3.	Doug Callison	Grand River Dam Authority	SPP	1, 3, 5
4.	Gary Cox	Southwestern Power Adminstration	SPP	1, 5
5.	David Dieterich	Omaha Public Power District	MRO	1, 3, 5
6.	Kim Donghyeon	Burns & McDonald	NA - Not Applicable	NA
7.	Allan George	Sunflower Electric Power Corporation	SPP	1
8.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

9.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
10.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
11.	Paul Lampe	City of Independence, Power & LIght Department	SPP	3
12.	Julie Lux	Westar Energy	SPP	1, 3, 5, 6
13.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
14.	Kyle McMenamin	Xcel Energy	SPP	1, 3, 5, 6
15.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
16.	Terry Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
17.	Randy Root	Grand River Dam Authority	SPP	1, 3, 5
18.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
19.	Sean Simpson	Board of Public Utilities, City of McPherson	SPP	1, 3, 5
20.	Angela Summer	Southwestern Power Administration	SPP	1, 5
21.	Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
9.	Group	Steve Rueckert	Western Eledtricity Coordinating Council										X

No additional members listed.

				1	2	3	4	5	6	7	8	9	10
10.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

				1	2	3	4	5	6	7	8	9	10
11.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted	Snodgrass	WECC	1
2.	Tim	Loepker	WECC	1
3.	John	Anasis	WECC	1
4.	Deanna	Phillips	WECC	1, 3, 5, 6
5.	Rebecca	Berdahl	WECC	3

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6.	Erika	Doot	WECC 3, 5, 6										
7.	Kristy	Humphrey	WECC 1										
8.	Don	Watkins	WECC 1										
9.	Fran	Halpin	WECC 5										
12.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				
	Additional Member	**Additional Organization**	**Region / Segment Selection**										
1.	Jessi Tucker	Kansas City Power & Light	SPP 1, 3, 5, 6										
2.	Jim Useldinger	Kansas City Power & Light	SPP 1, 3, 5, 6										
3.	Harold Wyble	Kansas City Power & Light	SPP 1, 3, 5, 6										
13.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
14.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
15.	Individual	Antonio Grayson`	Southern Company	X		X		X	X				
16.	Individual	Molly Devine	Idaho Power Company	X									
17.	Individual	Joe Couturier	SSOE Group										
18.	Individual	Michael Falvo	Independent Electricity System Operator		X								
19.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
20.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
21.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
22.	Individual	Rich Salgo	NV Energy	X		X		X					
23.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
24.	Individual	Andrew Z. Pusztai	American transmission Company	X									
25.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
26.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
27.	Individual	Larry Raczkowski	FirstEnergy Corp	X		X	X	X	X				
28.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
29.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
30.	Individual	Darryl Curtis	Oncor Electric Delivery	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
31.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
32.	Individual	Randall McCamish	City of Vero	X		X							
33.	Individual	J. S. Stonecipher, PE	Beaches Energy Services of theCity of Jacksonville Beach, Florida	X								X	
34.	Individual	Gregory Campoli	New York Independent System Operator		X								
35.	Individual	Patrick Brown	Essential Power, LLC					X					
36.	Individual	Tony Jankowski	Wisconsin Electric Power Company			X	X	X					
37.	Individual	Kathleen Goodman	ISO New England Inc	X	X	X		X	X				
38.	Individual	Brian J Murphy	NextEra Energy, Inc.	X		X		X	X				
39.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
40.	Individual	Thomas E. Foltz	AEP										
41.	Individual	Jason Marshall	ACES Power Marketing										

1. **The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The majority of the comments received requested clarification or explanation of why the SDT did what it did. Only one change, to the Time Horizon for Requirement R1, was made due to comments.

Several commenters remarked that there was a potential problem with relying on a definition being developed in another project that wasn't approved as yet. As has been explained previously, the SDT is working closely with the Reliability Coordination Standard Drafting Team (RC SDT) that is responsible for defining the term 'Reliability Directive'. The use of that term within this standard is somewhat generic in nature. The SDT believes that the progress in developing the definition is sufficient to warrant continued progress of Project 2007-03 without significant concerns of wasted effort or time. And, as shown in the Implementation Plan, the two projects will be filed at FERC together in one package.

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-day Operations, Real-Time Operations]

Organization	Yes or No	Question 1 Comment
Kansas City Power & Light Co.	Negative	Comments and concerns with the proposed standards have been expressed within the NERC comment form
American Electric Power	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Florida Municipal Power Agency	Negative	Please see FMPA comments submitted separately.
Xcel Energy, Inc.	Negative	Please refer to Xcel Energy's filed comments related to this project.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Negative	Please see comments submitted by Joe Petaski (Manitoba Hydro)
Bonneville Power Administration	Negative	See BPA's submitted comments
Wisconsin Electric Power Co.	Negative	See WE group comments
Xcel Energy, Inc.	Negative	Xcel Energy submitted comments in Standard Comment Form.
FirstEnergy Energy Delivery, FirstEnergy Solutions	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.
Ohio Edison Company	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.
Response: Thank you for submitting comments. Responses to your comments are addressed below.		
ReliabilityFirst Corporation	Abstain	ReliabilityFirst abstains and offers the same comments as submitted via the previous comment posting period.
Response: The SDT points RFC to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
Brazos Electric Power Cooperative, Inc.	Negative	Additional clarification is necessary that warrants our negative vote. See the issues raised in the comments by ACES Power Marketing.
ACES Power Marketing	No	We generally agree with TOP-001 and the changes since the last posting. However, we continue to believe that use of the language “know or expected to be” in Requirement R3 is confusing and that this is a case where brevity is more effective in communicating the requirement. We believe striking this clause will improve the clarity of the requirement. As

Organization	Yes or No	Question 1 Comment
		the clause is written now, it is not clear to whom it applies? We assume the SDT intended for the notification to be based on the expectation or knowledge of the TOP to whom the requirement applies. However, the clause is not clear on this but is rather a statement that appears to be some general knowledge or expectation. This opens the possibility of an auditor substituting their expectation or knowledge over the applicable TOP. Requirement R5 has a similar issue. We are concerned that the examples listed in Requirement R5 may be too simplistic and could be interpreted too literally. A change in load is one example. Thus, a simple reading of the requirement would imply that a Transmission Operator that has a 1 MW change in a 10,000 MW would be required to notify the Reliability Coordinator. Clearly, that is not what is intended. To resolve this issue, two solutions could be applied. One solution would be to state that changes must be significant. A second solution would be to strike the examples altogether. Requirements R10 and R11 are inconsistent. Requirement R10 states the Transmission Operator must inform the RC of “its actions” to mitigate an IROL or SOL that has been exceeded while Requirement R11 compels the Transmission Operator “to act or direct others to act” to mitigate an IROL or SOL that has been exceeded. While we consider that a Transmission Operator directing others to act is the same as taking action itself, it would appear Requirement R11 does not consider directed actions as the actions of the Transmission Operator. This would imply that Requirement R10 does not include communication of the directed actions since it applies to Transmission Operator actions. However, we do not believe exclusion of Transmission Operator actions was intended in Requirement R10. The simplest solution to align these two requirements more closely would be to

Organization	Yes or No	Question 1 Comment
		change “its” in Requirement R10 to “the”. In this way, Requirement R10 is not limited to only the actions taken directly by the Transmission Operator. The language in the Data Retention section regarding Requirements R7 and R9 needs to be made more consistent with the requirement. We are concerned that language could be interpreted as compelling the Transmission Operator to retain data for any IROL that is temporarily exceeded for a duration less than T_v or an SOL that is exceeded for a time that does not violate the criteria upon which it is based. Neither of these instances would represent a violation of either Requirement R7 or R9. Thus, the data is not necessary to be retained. Under the Compliance Enforcement Authority section, we suggest “entities” in the first bullet and “functional entities” in the second bullet should be changed to “registered entities”. This will make them consistent with one another and the function model. The “Reliability Functional Model Technical Document” describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.

Response: R3 & R5: The SDT disagrees. By utilizing the results of the required Operational Planning Analysis, the Transmission Operator will know what other entities are known or expected to be affected. Striking the clause will not provide clarity but open up other questions. No change made.

R5: The use of the term ‘significant’ would not provide any additional clarity as it is still a subjective term open to interpretation. Merely striking the examples does not provide additional clarity either as it leaves the situation completely open to interpretation. The SDT believes that including the examples provides sufficient clarity. Any auditor trying to use a 1 MW change on a 10,000 MW system will be hard-pressed to justify their actions. No change made.

R10: The SDT disagrees. If the commenter accepts that directing others to act is the same as taking action itself, then the SDT

Organization	Yes or No	Question 1 Comment
asserts that Requirement R10 is aligned with Requirement R11. No change made. Data retention: The SDT believes that by incorporating a reference to the requirements in question within the data retention language that the concern expressed by the commenter is not an issue. No change made. CEA: The SDT is using language here that has been utilized in multiple standards projects to date and was supplied by staff as accepted language. Furthermore, the SDT does not agree that the suggested changes will provided any additional clarity. No change made.		
Lakeland Electric	Negative	Please refer to comments submitted by FMPA.
Florida Municipal Power Pool	Affirmative	See FMPA Comments
Florida Municipal Power Agency; City of Vero; Beaches Energy Services of the City of Jacksonville Beach, FL	No	The existing TOP-001-1 R7 essentially requires communication to the RC and neighboring TOPs any time a Facility is to be switched. The new TOP-001-2 R5 will only require such communication when such switching would result in an "Adverse Reliability Impact" defined as: "The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection." This significantly reduces the requirements for communication / notification for switching Facilities. It is worthwhile to communicate switching of some Facilities whether or not they would result in an "Adverse Reliability Impact". Suggest rephrasing to something like any unplanned switching of Facilities not "noticed" through data provision of TOP-003-2. With the number of human error events that have occurred, we should not be reducing the communication / notification requirements. R8 is not needed since it is already covered in FAC-014-2 R5.2. As a result, R9, R10 and R11 ought to be modified to refer to FAC-014-2 rather than R8.
Response: R7: The SDT believes that notification for any switching event is contrary to good operating practice as it would load up the message queue with unnecessary information and could lead to an operator missing an important message within a large		

Organization	Yes or No	Question 1 Comment
group of unneeded messages. TOP-003-2 allows for an entity to request reliability-based information from another entity so they may include status on any piece of equipment that may possibly effect its operations. Therefore, the SDT does not agree that a reliability gap has been created. No change made. R8: The SDT notes that there are subtle differences in TOP-001-2 and FAC-014-2. FAC-014-2 provides a simple list of SOLs while TOP-001-2 is looking at particular SOLs that need special treatment. Therefore, there is no redundancy. No change made.		
Xcel Energy, Inc.	Negative	Drafting Team didn't address the Regional differences on the treatment of SOLs. R8 – Please clarify the difference between R8 of TOP-001-2, and R2 & R5 of FAC-014-2. We would expect in some regions, depending on the RC's SOL methodology, that this would be the same information. For example, in SPP, all Facility Ratings are considered SOLs. Compliance with R9 of TOP-001-2 will prove quite difficult in regions like this. Please clarify what the drafting team envisions being the difference between these two standards, and what is expected to be given to the RC under each. R9 - We appreciate the drafting team's efforts. However, we are still concerned that R9 will not allow the Transmission Operator the flexibility to identify the best SOL recovery approach, without incurring a violation of the requirement. Instead, the TOP may be forced to shed load in order to avoid violating the requirement. This is not ideal, especially when the situation could be mitigated successfully with alternative measures. It is not clear if an entity is allowed to use an RC-approved contingency plan to mitigate a situation that would cause a Facility Rating violation (i.e. the Facility Rating is the SOL), without also incurring a violation of R9. To further explain, if an entity foresees exceeding an SOL in its OPA, and obtains approval from the RC on their proposed contingency plan (which includes a Facility Rating violation), will that entity be considered in violation of R9 once the exceedance occurs and the contingency plan is implemented?
Response: The SDT does not agree that it is necessary to spell out any regional differences in the treatment of SOLs. The		

Organization	Yes or No	Question 1 Comment
requirements are generic in that respect as they should be. No change made. R8: The SDT believes that there are subtle differences in TOP-001-2 and FAC-014-2 that the commenter is missing. FAC-014-2 provides a simple list of SOLs while TOP-001-2 is looking at particular SOLs that need special treatment. Therefore, there is no redundancy. No change made. R9: There is nothing in this standard that ties the Transmission Operator to any particular plan or action so the SDT believes that the commenter's fears are ungrounded. No change made.		
National Association of Regulatory Utility Commissioners	Negative	Given the term Reliability Directive is being used as a defined term but does not yet exist as a defined term in the NERC Glossary and is not proposed to be a defined term in the Glossary with this proposal, it is premature to approve this revised standard.
Hydro One Networks, Inc.	Negative	The standard uses the term "Reliability Directive" which is currently and formally under development as part of another project. The posting states that this definition was agreed to by all affected project teams using it. However if the other project team formally charged with this definition's development, changes it, then this standard and perhaps others, will have to be revisited.
Utility Services, Inc.	Negative	There is use of the term "Reliability Directive" in the standard which is currently and formally under development as part of another project. The posting states that this definition was agreed to by all affected project teams using it, however if the other project team formally charged with this definition's development, changes it, then this standard and perhaps others, will have to be revisited. Bringing these standards forward seems inefficient and problematic.
Response: The SDT appreciates your concerns, but has always intended to deal with the coordination issue involved here in a decisive manner. As has been explained previously, the SDT is working closely with the RC SDT that is responsible for defining the term 'Reliability Directive'. The use of that term within this standard is somewhat generic in nature. The SDT believes that the		

Organization	Yes or No	Question 1 Comment
progress in developing the definition is sufficient to warrant continued progress of Project 2007-03 without significant concerns of wasted effort or time. The RTO SDT (Project 2007-03) and the RC SDT's project (Project 2006-06) will be filed together at FERC. No change made.		
Santee Cooper	Negative	In R8, SOLs are identified according to each entity's SOL methodology. This requirement seems to assume a certain methodology for identifying SOLs. Local area issues such as the examples cited in the rationale may not be of consequence to the BES and not considered an SOL. Also, over-communication of local area issues to the RC will inundate them and could become a detriment to the reliability of the BES. We believe that entities should be allowed to report SOLs according to their required methodology they have established. What was the rationale of reducing the implementation time from twenty-four months to twelve months?
Response: R8: SOLs are developed through a required methodology in FAC-014-2. Nothing in TOP-001-2 changes that fact. Requirement R8 is intended solely for those SOLs, that while not IROLs, are more important to the Transmission Operator Area than a typical SOL would be. No change made. IP: The effective date was changed following numerous comments to the sixth posting that asserted the implementation plan would take excessive time and needed to be shortened. It was also based on the fact that the proposed requirements represent what is already being done in the field in many areas.		
INTELLIBIND	Negative	Inclusion of "examples" is not appropriat and leads to a compliance conflict on whether these examples must be addressed or not. R8, 9 and 11 place unneeded additional burden on entities to prove they are properly complying.
Response: The SDT believes that the language of the requirement (and examples) is such that that the commenter's fears are unwarranted and will not lead to conflict. No change made.		

Organization	Yes or No	Question 1 Comment
The commenter has not supplied any information on the details of why there is an unneeded burden. Therefore, the SDT is unable to reply. Proof of compliance with a requirement is part of a mandatory compliance mechanism. In recognition of this compliance burden, the requirements mentioned were carefully crafted with the end in view that a registered entity should be able to affirmatively prove compliance. No change made.		
MidAmerican Energy Co.	Negative	NERC standards cannot be vague and undefined or NERC interprets the standard and creates new requirements through the Compliance Application Notice process. The rational specified for R8 shows that R8 deals with a Transmission Operator defined special subset of SOLs. However, the current wording in R8 does not use the wording "special subset of SOLs as defined by the TOP". The standard uses "as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis". This is not clear enough for a black and white compliance audit and therefore is inadequate. Further in R9 continous duration remains undefined. Therefore, specific wording needs to be added to show that R9 applies to the "special subset of SOLs with there corresponding continous duration timeframes as defined by the TOP". Last, the the same wording and definition must be applied to FAC-011-2 R2 to remain consistent and clear.
Response: The rationale is simply an explanation of Requirement R8 and is intended to ensure that the responsible entity and auditor understand the requirement – it is the language in the requirement, not the language in the text box, that is enforceable. Therefore, there is no inconsistency in the wording. No change made. Continuous duration is a common term and the Webster's dictionary meanings can and should be applied. The reference in Requirement R9 to Requirement R8 makes it clear as to what is being referenced. No change made. The SDT has reviewed FAC-011-2, Requirement R2 and does not believe that any changes are required in order to maintain consistency as the methodology hasn't been changed. No change made.		

Organization	Yes or No	Question 1 Comment
Detroit Edison Company	Negative	R3- The sentence should read "… inform its Reliability Coordinator and other Transmission Operator(s), …" The word other is missing in the current draft. R6- The statement "… negatively impacted interconnected NERC registered entities…" is to vague. This could be an easy trip up during an audit. M6- same as R6- The statement "… negatively impacted interconnected NERC registered entities…" is to vague. VSLs- R6- The statement "… negatively impacted interconnected NERC registered entities…" is to vague.
Response: R3: The SDT asserts that 'other' is understood and no additional clarity would be provided by adding it. No change made. R6, M6, & VSL: The SDT believes that a 'negatively impacted' entity is clear and not vague. No change made.		
Westar Energy	Negative	SDT has not adequately addressed previous comments.
Response: Without specifics, the SDT is unable to respond.		
Wisconsin Electric Power Marketing; Wisconsi Energy Corp.	Negative	The SDT's response for previous comments on R6 is that "The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. " If that is the intent of the requirement then the requirement should state that. Also, "negatively impacted" needs to have some sort of bounds. Loss of $1 in revenue is a negative impact.
Response: The SDT believes that the intent is clear and that no further explanation is required. No change made. As the requirement is dealing with telemetry outages, the impact is in loss of data and information as it relates to reliability. Revenue is not within the scope of reliability standards. No change made.		

Organization	Yes or No	Question 1 Comment
Commonwealth of Massachusetts Department of Public Utilities	Negative	There is use of the term "Reliability Directive" in the standard which is currently and formally under development as part of another project. The posting states that this definition was agreed to by all affected project teams using it, however if the other project team formally charged with this definition's development, changes it, then this standard and perhaps others, will have to be revisited. Bringing these standards forward seems inefficient and problematic for many. Also in Requirement 8 there was an issue expressed by one RSC member that System Operating Limits are local limits and should not be subject of part of the NERC standards and the requirement as written creates a "subset" of SOLs that affect reliability. This could create an overly complicated standard and could lead to compliance difficulties.
Response: As has been explained previously, the SDT is working closely with the RC SDT that is responsible for defining the term 'Reliability Directive'. The use of that term within this standard is somewhat generic in nature. The SDT believes that the progress in developing the definition is sufficient to warrant continued progress of Project 2007-03 without significant concerns of wasted effort or time. The RTO SDT (Project 2007-03) and the RC SDT project (Project 2006-06) will be filed together at FERC. No change made. The SDT does not believe that Requirement R8 creates an overly complicated standard or creates compliance difficulties. This requirement was added quite some time ago at the behest of industry as shown in earlier posted comments. There is nothing complicated about it and it is in the control of the Transmission Operator as to how to proceed. No change made.		
Texas Reliability Entity	No	1) Definitions: Texas RE does not agree with the proposed definition of “Reliability Directive” and encourages the SDT to look past a compliance based outlook regarding the word “directive”. If there is no Reliability Standard support for use of directives to AVOID emergencies, emergencies will continue to occur. Consider using the broader defined term “Operating Communication” from COM-003 rather than “Reliability Directive” in this standard.

Organization	Yes or No	Question 1 Comment
		2) R1: This requirement, as written, states that the BA, GOP, DP, and LSE must comply with Reliability Directives, which, by definition, are only issued in Emergencies or to prevent instability or Cascading. There is not a requirement in the TOP or IRO standards that obligates a Registered Entity to comply with other directives issued by the TOP or RC used in operating the grid in a reliable manner. For example, some generator operators exceed the operating basepoint that is communicated to the unit by the ISO, which creates congestion and overloads the transmission system. Under the proposed R1 language, there is no requirement for an entity to comply with this type of directive, since it is not a "Reliability Directive" until an Emergency occurs. 3) R3: Requirement R3 seems to be missing some words. It doesn't say WHAT the TOP should inform other entities about. Also, it is not clear if this requirement is supposed to be about planning ("expected to be affected by anticipated Emergencies") or real-time operations ("known to be affected by actual Emergencies") or both. If the latter is intended, the Time Horizon should include Real-Time Operations and Same Day Operations. We suggest changing the language to "Each Transmission Operator shall inform its Reliability Coordinator and other affected Transmission Operator(s) about each actual or anticipated Emergency , which may be determined in Real-time or based on its assessment of its Operational Planning Analysis" 4) R4: Reinsert Generator Operator applicability from old R6. The stated reason for removal of Generator Operator is incorrect and violates the Functional Model which states that a Balancing Authority may direct "resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time" and "direct "Generator Operators to implement redispatch for congestion management". Both of those type actions may include rendering emergency assistance. 5) R5: The requirement implies, but does not specifically state a time frame

Organization	Yes or No	Question 1 Comment
		for informing the RC. The RC must be informed in sufficient time in order to respond to the system condition. The phrase “unless conditions do not permit” is ambiguous and should be made more definite. We suggest rewriting R5 as follows: “Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas within a timeframe that is sufficient for the RC and affected Transmission Operators to respond to the system condition, unless communication capabilities have failed.” The Time Horizon should also include Operations Planning since the Requirement language includes “known or expected.” 6) R6: There is a need to include Generator Operator in this requirement. There is no clarification in the mapping document regarding the loss of the applicability to the Generator Operator (previously in TOP-001-1 R3). 7) R8: This requirement, as written, states that the TOP must inform the RC of SOLs based on its assessment of its Operational Planning Analysis, which, by definition, is an analysis for the next day’s operation that may occur either a day ahead or as much as 12 months ahead. SOL violations can occur in Real-Time (e.g., transmission thermal limit violations, voltage violations, etc.) due to forced outages from storms or equipment failures that may not have been studied under the Next-Day analysis and various other real time conditions. We suggest rewording the requirement to read “Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based ON ANTICIPATED OR ACTUAL EMERGENCIES OCCURRING IN REAL-TIME OR BASED on its assessment of its Operational Planning Analysis.” It is important to recognize the Real-Time issues because several of the Requirements following Requirement 8 refer to SOLs “identified in Requirement R8.” Additionally, since the definition of SOL includes post-

Organization	Yes or No	Question 1 Comment
		contingency criteria, contingencies are not limited to Operational Planning Analysis timeframes. The VSL language also needs to accommodate Real-Time considerations. 8) R9: See our comment regarding R8 - there is a reliability gap because SOLs identified in Real-Time (as opposed to those identified in the Operational Planning Analysis timeframe) are not included. 9) R10: See our comment regarding R8 - there is a reliability gap in the actions needed to return the system to within limits for SOLs identified in Real-Time as opposed to those identified in the Operational Planning Analysis timeframe. 10) R11: See our comment regarding R8 - there is a reliability gap for SOLs identified in Real-Time as opposed to those identified in the Operational Planning Analysis timeframe.11) What is the intended difference between “TOP shall not operate outside any SOL” in R9 and “TOP shall act or direct others to act to mitigate both the magnitude and the duration of exceeding . . . an SOL” in R11? The same action or inaction would likely result in violations of both requirements, resulting in a “double-jeopardy” situation.
Response: 1. The SDT is aware of the work being done with COM-003 as it has maintained close coordination with that SDT. In this case, the SDT believes that the requirements in TOP-001-2 best align with the use of Reliability Directive. Any problems with the proposed definition should be taken up with the RC SDT in Project 2006-06. No change made. 2. The SDT believes that other market protocols, standards and operating protocols and mechanisms are in place today to take care of the type of situations that the commenter has noted. No change made. 3. The SDT does not believe the suggested change adds any clarity. The SDT believes that it is clear as to what needs to be communicated. Since Operational Planning Analysis is generally analyzed at least a day ahead, the SDT, in response to numerous comments in the last posting, changed the Time Horizon to just Operations Planning. No change made. 4. The SDT stands by its reasoning for deletion of the Generator Operator as consistent with the Functional Model v5. No change made.		

Organization	Yes or No	Question 1 Comment
5. The SDT does not believe that the suggested language provides any additional clarity. Requirement R5 is more pertinent to Real-time than Operations Planning which is covered in Requirement R3. No change made. 6. There is no relevance between TOP-001-1, Requirement R3 which concerns reliability directives and this requirement which deals with telemetry outages. If a Generator Operator has telemetry outages it will be noted to the Transmission Operator or Balancing Authority and would be reported as part of their information. No Change made. 7, 8, 9, & 10. The SDT believes that Operational Planning Analysis includes the study of Contingencies and as such will include scenarios that include such conditions as the commenter has pointed out. The SDT reminds the commenter that TOP-002-3 requires the study of all SOLs and that nothing has changed with regard to an entity's responsibilities to operate a reliable system. TOP-001-2 is simply elevating a subset of SOLs to receive special attention. No change made.		
Oncor Electric Delivery	No	Oncor believes that the Reliability Coordinator is in the best position to determine who the negatively impacted interconnected registered entities are and to effectively coordinate communication efforts after receiving the initial planned outage request from the originating entity. In addition, the term "negatively impacted interconnected registered entities" is too broad and too subjective. As a result, we recommend R6 be revised to: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
Response: The SDT believes that the Transmission Operator can, and does, know who will be impacted by outages of telemetry equipment. Placing this responsibility at the Reliability Coordinator level would place an unnecessary burden on those entities and deflect them from their reliability responsibilities. No change made.		
Bonneville Power Administration	No	BPA does not believe that the drafting teams' consideration of our previously submitted comments during the last round was adequate. The response appeared to be based on the assumption that the SOL or IROL was based on a thermal limit, not a stability limit. Since a system can go unstable in less than 1 second, the drafting team's response that, "ratings

Organization	Yes or No	Question 1 Comment
		include the qualifiers of time...” did not make sense to us in the context of a “stability limit”. As stated in BPA’s previous comments, it takes a definite amount of time to readjust the system (change schedules, move generation, or perform other actions) in order to get actual flows down to reliable operating limits when flows have exceeded limits. The standards need to clearly articulate how much time the responsible entities have to accomplish this. The current standard TOP-004-2, R4 clearly articulates a 30 minute rule for this. TOP-001 needs to do the same, especially if TOP-001 will replace TOP-004-2. Previous Comments: Given the potential uncertainty regarding the 30 Minute Rule, BPA suggests adding more clarity to the standard TOP-001-2 as the new draft could be interpreted to mean that one would need to get the flows below the SOL immediately. BPA believes this is not practical because it takes a definite amount of time to change schedules, move generation, or perform other actions in order to reduce loadings on facilities. BPA believes the new draft should include guidance as to how much time the BA or Transmission Operator would be allowed in order to reduce flows when there is an SOL violation. BPA suggests that more clarity be provided and/or the 30 minute rule be added back to the standard. Additional New Comments:TOP-001 introduces a new term and definition, Reliability Directive. This term is used in R1 of the standard in conjunction with two other defined terms, 'Emergency' and 'Adverse Reliability Impacts'. The time horizon described for R1 is ‘Operations-Planning’. The timeframes for which this standard applies are 'Operations-Planning', 'Same-Day Operations' and 'Real-Time'. However, if we review the definitions associated with 'Emergency' and 'Adverse Reliability Impacts', it is clear that these terms are used for events that occur only during real time operations. BPA recommends that R1 be re-worded so that the Time Horizons are consistent with the terms used in the standard; that the Reliability Directive definition be clarified so that the timing of the

Organization	Yes or No	Question 1 Comment
		directive is identified; and that use of the terms 'Emergency' and 'Adverse Reliability Impact' be consistent with their definitions, and the 30 minute rule for getting actual flows back within a reliable limit be inserted. BPA recommends that the applicability of R6 be expanded to also include Generation Operators. The intent of this requirement is for those entities with "telemetering equipment, control equipment and associated communications channels" to coordinate outage of such equipment with its Reliability Coordinator and negatively impacted interconnected NERC registered entities. Though Generation Operators have such equipment, as written, this requirement does not require that the coordinate such outages in the same manner as Balancing Authorities and Transmission Operators are required to under this requirement.

Response: SOLs, by definition, include Stability ratings and those ratings, like all ratings, have a time element associated with them. Therefore, by using ratings and the time elements associated with them, the SDT has provided a definitive timeframe that will provide greater protection to system elements than what was previously stated as 30 minutes may be too long in certain situations. If a stability rating with a T_v of 1 second is the basis for an SOL, then no time in exceedance of the magnitude limit is allowable, and a Transmission Operator facing that issue would have plans in place to avoid exceedance of that limit. No change made.

The SDT is in agreement with the commenter and has deleted Operations Planning from the Time Horizons. From the latest approved version of the Standards Process manual: "Time Horizon: The time period an entity has to mitigate an instance of violating the associated requirement."

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-day Operations, Real-Time Operations]

Organization	Yes or No	Question 1 Comment
The SDT asserts that if a timing element is required for a Reliability Directive that the Reliability Directive will include such a timing element. No change made. With the change in the Time Horizons cited above, the terms are now consistent. No further change made. SOLs, by definition, include Stability ratings and those ratings, like all ratings, have a time element associated with them. Therefore, by using ratings and the time elements associated with them, the SDT has provided a definitive timeframe that will provide greater protection to system elements than what was previously stated as 30 minutes may be too long in certain situations. No change made. The SDT stands by its reasoning for deletion of the Generator Operator as consistent with the Functional Model v5. No change made.		
PNGC Group Comments	No	Comments: The PNGC comment group believes there should be a distinction in the "Applicability" section of the standard distinguishing between "Scheduling DP/LSE" and "Non-scheduling DP/LSE". PNGC members are small rural cooperatives that are "Full service BPA customers." This means is that BPA is our power supplier and scheduling agent and therefore handles all scheduling, tagging, dispatching of resources and curtailments of load from breakers on BPA's system for PNGC members. According to a letter from the WECC Reliability Coordinator (VRCC and LRCC) none of PNGC's members will ever receive a "Reliability Directive". Such a Directive would be sent to either a Balancing Authority (BA), or a Transmission Operator (TOP). In fact, the Bonneville Power Administration (BPA) is the BA and TOP for many of our members so R1 and R2 are nothing more than a clerical exercise for many DP/LSE entities. We estimate there are over 100 entities that are BPA Full Service customers that are in a similar position and making this standard applicable to them does nothing to enhance reliability. A simple declarative statement in the Applicability section of the standard could focus the intent of the SDT on those entities that need it while lessening the compliance risk and clerical burden for other entities that the standard should not apply to. We suggest:4.

Organization	Yes or No	Question 1 Comment
		Applicability4.1 Balancing Authority4.2 Transmission Operator4.3 Generator Operator4.4 Distribution Provider: With Real-time Operations desk4.5 Load-Serving Entity: With Real-time Operations desk
Response: The SDT believes that the current wording is appropriate for a continent-wide standard. If an entity never receives a Reliability Directive then there is nothing for them to do. No change made.		
Kansas City Power & Light	No	Continuous duration" in R9 is not a defined term and will cause uncertainty and debate under audit as to what time frame this represents. Recommend R9 be modified to reflect the time basis established through the methodology to develop the SOL for the applicable facilities. Suggested modification for R9:Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that exceeds the Facility Rating or Stability criteria upon which the SOL is based.
Response: The SDT sees no additional clarity in the suggested wording change. Continuous duration is a common term and the Webster's dictionary meanings can and should be applied. No change made.		
MRO NSRF	No	For R9, the drafting team did not address "continuous duration". Many entities had commented that the term is vague. Is continuous duration, 8 hours or 15 minutes? For IROL limit violations or Unknown State conditions, the entity has 30 minutes to mitigate the situation.
Great River Energy	Affirmative	Great River Energy agrees with the comments of the MRO NSRF
Response: Continuous duration is a common term and the Webster's dictionary meanings can and should be applied. No change made.		
Idaho Power Company	No	I don't think that this requirement should be retained. With e-tag requirements, mid-hour scheduling and the ability to process an emergency

Organization	Yes or No	Question 1 Comment
		tag at any time it seems like an interchange. What is emergency assistance?
Response: Emergency assistance can mean many things such as a change in dispatch or load shed, etc., that do not result in a energy transaction or e-Tag. e-Tag is not a reliability-based tool and shouldn't be relied on to cover operating situations in Real-time. No change made.		
Consolidated Edison Co. of New York	Affirmative	See NPCC group comments
Northeast Power Coordinating Council	No	It is written in FAC-014-2 R5.2: R5.2. The Transmission Operator shall provide any SOLs it developed to its ReliabilityCoordinator and to the Transmission Service Providers that share its portion of theReliability Coordinator Area.This already mandates that the Transmission Operator provide its Reliability Coordinator SOLs. This requirement and TOP-001 R8 must be made to agree.As explained in the redline version of TOP-001: "Rationale: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations."It is understood that the impacts of some SOLs may attract increased attention because of the operational implications of them being exceeded. It must also be realized that every SOL has a reliability impact. The added wording adds unneeded complication to the Requirement. Will the proposed requirement create a new class of SOLs that might include any that might be "intermittent" in nature, such as those occurring during televised events, etc.? This becomes a moving target, and it may become problematic for keeping track of those SOLs to which these requirements apply, i.e., those that require notification to the Reliability Coordinator, versus those which don't. Regardless, operator responses to any SOL's on their systems should

Organization	Yes or No	Question 1 Comment
		be the same in terms of swiftness and a sense of urgency. The phrase "supporting reliability internal" is used in R8. What constitutes "supporting reliability internal"? This may present compliance issues. Experience has shown that the use of the terms internal, external, local, wide area have presented auditing difficulties that generated documentation issues.
Response: The SDT asserts that there are subtle differences in TOP-001-2 and FAC-014-2. FAC-014-2 provides a simple list of SOLs while TOP-001-2 is looking at particular SOLs that need special treatment. Therefore, there is no conflict. No change made. The commenter is leaving out part of the phrase thus creating a problem in their mind where there is none if everything is taken in context. The whole phrase is "…supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis." When shown in this complete version, the SDT asserts that it is clear as to what is meant and what needs to be done. No change made.		
Manitoba Hydro	No	Manitoba Hydro is voting negative on TOP-001-2 for the following reason:R8 and R9 - In the absence of the rationale box in the final approved version of the standard, R8 is extremely unclear. All SOL's support reliability based on an assessment of operational planning. The requirement (R9) prohibits operation outside any SOL "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based." However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. The term continuous duration is undefined and as such makes the standard subject to interpretation. It would appear that the standard expects the system operator to do something more than would be done for an IROL.
Response: The SDT fails to see where the absence of a rationale box will make Requirement R8 unclear and the commenter provides no specifics for the SDT to respond to. The SDT believes that Requirement R8 is clear. No change made.		

Organization	Yes or No	Question 1 Comment
The time element for mitigation of the problem is the key to Requirement R9 and the reason for the proposed wording. No change made. Continuous duration is a common term and the Webster's dictionary meanings can and should be applied.		
Consumers Energy	No	The Reliability Directive definition is not strong enough and leaves too much to interpretation. We feel that the other requirements and items in the standard are acceptable and we could support this version if the definition had more clarity.
Response: Reliability Directive is being developed and defined by Project 2006-06 and the term is simply being utilized in this standard. The commenter should provide specific comments to Project 2006-06 during their next posting. No change made.		
AEP	No	In the previous comment period, AEP requested clarification on whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumed this was based on Real Time Flow, but we encouraged the drafting team to provide clarifying language to make it more clear to the reader. The drafting team responded by noting that IROLs have been defined as both pre-contingent and post-contingent, and that the exact definition of the IROL must be honored. However, no such clarifying language was added to the standard. Time and time again, industry has provided comments to standard drafting teams in an effort to help avoid CANs, Interpretation Requests, and to increase the consistency of interpretation by both CEA's and industry. In this case, while the team provided insight in their comments, the resulting lack of changes to the standard still leave unnecessary ambiguity that could be easily addressed. Ambiguity of any kind deters from, rather than promotes, the reliability of the BES. Until such clarification is added to the standard itself, AEP cannot support the drafting team's efforts in revising TOP-001-2. R1: The timeframe should be identified.

Organization	Yes or No	Question 1 Comment
Response: The SDT believes that the definition of IROL speaks for itself and therefore that no further explanation is required within the standard. No change made. The SDT believes that if a timing element is required for a Reliability Directive that the Reliability Directive will include such a timing element. No change made.		
New York Independent System Operator	No	The SDT did not provide reasonable assurance that documented determination of 'Reliability Directive' identification was sufficient to meet R1, in the absents of explicit identificaation during every verbal communication. We believe it is not clear to an auditor that written procedures would be an adequate level of 'identification. A possible solution would be to add R1.1 and spell out that identification of Reliability Directive shall be communicated through approved procedures or verbal identification. In addition, Requirement 11 gives the TOP the authority to "...act or direct others to act..." to mitigate IROL and certain SOL exceedances. Is it the intent of the SDT that the TOP can direct any of the entities to which this standard is applicable? Also SDT should consider a change to say "... act or issue a Reliability Directive to ....' This ties the requirement back to R1 with an obligation to complete the directive. The NYISO is also concern with the use of the definition of 'Reliability Directive' that has not been approved. We recommend balloting TOP-001 simultaneously with the RC Project that includes the definition. As it stands we support the proposed definition.
Response: Communication of Reliability Directives is governed by the COM standards. Comments on same should be directed to Project 2006-06 the next time that project posts for comment. TOP-001-2 uses the term and says nothing about how it is implemented. No change made.		

Organization	Yes or No	Question 1 Comment
It is the intent of the SDT that the Transmission Operator can direct any entity shown in applicability. The SDT sees no additional clarity being provided with the suggested change. No change made. The TOP standards will be filed at FERC jointly with the Project 2006-06.		
SSOE Group	No	TOP-001-2Grammatical: R8 and its supporting rationale refers to a term SOL. The term is 'defined' later in R9. The 'definition' should probably be defined at the time of its first usage. R11 The TO directs someone to do something. However, who is directed is not defined. Is it directed to the RC?
Response: Agree – the SDT moved the definition of the acronym from Requirement R9 to Requirement R8. It is directed to the entity that the Transmission Operator believes can correct or help to correct the problem. Since that entity can't be identified ahead of time in a standard, the SDT believes it is best left as is. No change made.		
Duke Energy	No	While the drafting team has made several improvements to this standard, we believe these additional changes are needed: o The definition of Reliability Directive includes the defined term "Adverse Reliability Impact", which should be replaced by the actual wording of latest (8/4/2011) BOT-approved definition of "Adverse Reliability Impact", since it has NOT yet been approved by FERC. o R3 places the responsibility on a Transmission Operator to possess tools it does not currently utilize. Most companies will study their own area and possibly one or two busses out. In order to be compliant to this standard, it would appear a Transmission Operator would need to possess study tools which are currently utilized by the Reliability Coordinator. Suggest considering adopting language where the Transmission Operator requests assistance in identifying impacts outside their direct interconnects. Suggested rewording: "Each Transmission Operator shall work in

Organization	Yes or No	Question 1 Comment
		conjunction with its respective Reliability Coordinator to inform other Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: High] [Time Horizon: Operations Planning,]”. o R4, as written, does not consider an entity that might be under the control of an RTO. A Transmission Operator, as a member of an RTO, cannot take actions without the permission unless during an emergency where cascading outages, loss of equipment etc. is involved. If the event described in R4 as currently written is not an immediate emergency, the Transmission Operator would need to gain permission of the RTO to comply. Suggest wording changes to take into consideration entities whose facilities are under RTO control. Suggested rewording: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that appropriate agreements are in place, and the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. In the event the Transmission Operator is under the purview of a Regional Transmission Organization (RTO), the Reliability Coordinator of the RTO shall work with its Transmission Operators in requesting available emergency assistance. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]”. o R5 - Similar comment to R3. This requirement places the responsibility on a Transmission Operator to possess tools it does not currently utilize. Most companies will study their own area and possibly one or two busses out. In order to be compliant to this standard, it would appear a Transmission Operator would need to possess study tools which are currently utilized by the Reliability Coordinator. Suggest considering adopting language where the Transmission Operator requests assistance in identifying impacts outside their direct interconnects. Suggested rewording: “Each

Organization	Yes or No	Question 1 Comment
		Transmission Operator shall inform its Reliability Coordinator, who shall assist in identifying other Transmission Operators of its operations that are known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations include but are not limited to relay or equipment failures, and changes in generation, Transmission, or Load. [Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]”. o R6 - Strike the word “negatively”, since no one will be “positively” impacted. o R6 needs to be clarified as to the intent. Does registered entity mean the corporation, or does registered entity mean a TO, BA etc. Suggestion would be to remove NERC registered from the language. o R8 - The SDT has included a Rationale for SOLs that deserve increased attention. Several examples cited in the Rationale are for service to local load, and while the local loads may be important loads, the associated SOLs would have no impact on BES reliability. R8 requires the TOP to inform the RC of such SOLs, and we question why the RC needs to be informed of SOLs that only impact service to local loads. We believe that the phrase “supporting its internal area reliability” should be further clarified in some way. The inclusion of the undefined concept of “supporting internal area reliability” creates undue compliance risk, since auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”. With no clarification, it is conceivable that every SOL on a TOP’s system could be considered to support its “internal area reliability”. Communicating all SOLs would inundate the RC with unneeded information, which we believe would be detrimental to reliability. If this requirement stays in the standard, it needs to be reworded to indicate that any SOLs identified are identified at the sole discretion of the TOP.

Organization	Yes or No	Question 1 Comment
		o R8 - Change the phrase “as supporting” to “in support of”. o R9 - Strike the word “would” and add an “s” to “cause”.

Response: R1: Comments on the definition should be sent to Project 2006-06 the next time it posts. This project utilizes the proposed definition in a generic manner. No change made.

R3 & R5: No tool other is specified in this standard and the modeling requirements for a Transmission Operator have not been changed by this standard. The Transmission Operator will be judged on the merits of its model elsewhere and would simply be applying that model here. No change made.

R4: There is nothing in this standard that precludes a Transmission Operator from obtaining approval to take action if such approval is necessary. No change made.

R6: While no one may be positively impacted there are any number of entities that won’t be impacted at all. ‘Negatively’ was added at the request of previous commenters and seems appropriate to the SDT. No change made.

R6: NERC registered entity was added to the requirement due to comments in previous postings where commenters were concerned about limiting the reach of the requirement to non-NERC entities. The SDT believes that it is clear that messages are to be sent to appropriately identified entities.

R8: The reason for the notification is that the specified SOLs are to be treated differently than other SOLs. The SDT believes that the Transmission Operator is uniquely qualified to determine such SOLs. No change made.

R8 & R9: The SDT sees no additional clarity being provided by the suggested wording changes. No change made.

Organization	Yes or No	Question 1 Comment
ReliabilityFirst Corporation	Abstain	ReliabilityFirst abstains and offers the same comments as submitted via the previous comment posting period.

Response: The SDT points RFC to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.

Organization	Yes or No	Question 1 Comment
Seattle City Light	Affirmative	The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting

Organization	Yes or No	Question 1 Comment
		team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 Yes Comments: R4. calls for rendering emergency assistance as requested and available to other TOPs, provided that the requesting entity has implemented its "comparable" emergency procedures. The word "comparable" is not very well defined so for example, if the requesting entity implemented load shedding to reduce line loading below SOL, would this requirement obligate the entity asked for assistance to shed its load as well because the load shedding option is almost always available? Please state the requirement more clearly. R11. calls for each Transmission Operator to act or direct OTHERS to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8, yet there are no requirements directing OTHERS to COMPLY with these directives. R.1 requires BA, GOP, DP and LSE to comply with the reliability directives issues by ITS Transmission Operator, but not by OTHER Transmission Operators. There could also be potential for confusion and double jeopardy if there are competing transmission paths or facilities supporting reliability internal to the Transmission Operators. It should be the Reliability Coordinator task to direct OTHERS to act to mitigate SOL violations.
Response: Comparable is a well defined term and the Webster's use is in play here. Comparable does not mean exactly and leaves the entity some flexibility in how to react. No change made. Requirement R1 does require compliance. The use of the term 'its' is appropriate as a transmission Operator can't issue orders to a Balancing Authority that is outside of its area. If such an order was deemed necessary, it would have to be relayed by that Balancing Authority's Transmission Operator thus 'its' is the appropriate term. No change made.		
ISO New England, Inc.	Affirmative	TOP-001 Standard uses an undefined term "Reliability Directive" which is

Organization	Yes or No	Question 1 Comment
		being proposed in the Reliability Coordinator Standards project. We believe that NERC should post these inter-related projects simultaneous in order to achieve industry support to move these important projects forward. If the RTO Project is approved, it should only be presented to the BOT simultaneously with an approved RC Standards project. Additionally, if the definition of "Reliability Directive" is modified in any way in the Reliability Coordinator Standards project, this would be a material change to this standard and could result in company's filing comments in opposition to FERC.
Response: As has been explained previously, the SDT is working closely with the RC SDT that is responsible for defining the term 'Reliability Directive'. The use of that term within this standard is somewhat generic in nature. The SDT believes that the progress in developing the definition is sufficient to warrant continued progress of Project 2007-03 without significant concerns of wasted effort or time. No change made.		
City Utilities of Springfield, Missouric	Negative	City Utilities of Springfield, MO supports the comments from SPP.
Southwest Power Pool, Inc.	Affirmative	We continue to disagree with the successive ballot process that forces entities to decide on a voting position concurrent with the submittal of comments on the same. NERC needs to explore other ways to expedite the voting/comment process without forcing industry to have faith that changes will be made after approval. Although SPP votes in favor of this standard, we have outstanding comments that should be addressed. We have submittted them in the standards processs and reiterate some of them here. The Purpose Statement is too general and does not provide any direction of how the proposed standard will meet its stated intent. As written the Purpose Statement is applicable to any NERC standard that exists or can be imagined. We suggest additional wording of how this particular standard intends to do what it intends to is needed. For example, "...by requiring

Organization	Yes or No	Question 1 Comment
		applicable entities to have the data necessary to perform reliability analyses and real-time monitoring." While we agree with what we believe to be the intent of R9, using the word "continuous" without sufficient context remains ambiguous so as to prevent clear interpretation by all parties. We would suggest replacing the word "continuous" in R9 with "applicable". The timing criterion associated with an SOL should be associated with the timing criterion of the Facility Rating or Stability criteria. The revised requirement would read: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for the applicable duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
Response: The SDT is a process user and does not determine the elements of the process. If the commenter has problems with the successive ballot concept, it should be directed to the NERC Standards Committee. The stated changes to the Purpose Statement have no relevance to TOP-001-2. No change made. The SDT does not see where any additional clarity has been added by the suggested change. No change made.		
Southwest Transmission Cooperative, Inc.	Affirmative	We generally agree with TOP-001 and the changes since the last posting. However, we continue to believe that use of the language “know or expected to be” in Requirement R3 is confusing and that this is a case where brevity is more effective in communicating the requirement. We believe striking this clause will improve the clarity of the requirement. As the clause is written now, it is not clear to whom it applies? We assume the SDT intended for the notification to be based on the expectation or knowledge of the TOP to whom the requirement applies. However, the clause is not clear on this but is rather a statement that appears to be some general knowledge or expectation. This opens the possibility of an auditor substituting their expectation or knowledge over the applicable TOP. Requirement R5 has a similar issue.

Organization	Yes or No	Question 1 Comment
		We are concerned that the examples listed in Requirement R5 may be too simplistic and could be interpreted too literally. A change in load is one example. Thus, a simple reading of the requirement would imply that a Transmission Operator that has a 1 MW change in a 10,000 MW would be required to notify the Reliability Coordinator. Clearly, that is not what is intended. To resolve this issue, two solutions could be applied. One solution would be to state that changes must be significant. A second solution would be to strike the examples altogether. Requirements R10 and R11 are inconsistent. Requirement R10 states the Transmission Operator must inform the RC of "its actions" to mitigate an IROL or SOL that has been exceeded while Requirement R11 compels the Transmission Operator "to act or direct others to act" to mitigate an IROL or SOL that has been exceeded. While we consider that a Transmission Operator directing others to act is the same as taking action itself, it would appear Requirement R11 does not consider directed actions as the actions of the Transmission Operator. This would imply that Requirement R10 does not include communication of the directed actions since it applies to Transmission Operator actions. However, we do not believe exclusion of Transmission Operator actions was intended in Requirement R10. The simplest solution to align these two requirements more closely would be to change "its" in Requirement R10 to "the". In this way, Requirement R10 is not limited to only the actions taken directly by the Transmission Operator. The language in the Data Retention section regarding Requirements R7 and R9 needs to be made more consistent with the requirement. We are concerned that language could be interpreted as compelling the Transmission Operator to retain data for any IROL that is temporarily exceeded for a duration less than Tv or an SOL that is exceeded for a time that does not violate the criteria upon which it is based. Neither of these instances would represent a violation of either Requirement R7 or R9. Thus,

Organization	Yes or No	Question 1 Comment
		the data is not necessary to be retained. Under the Compliance Enforcement Authority section, we suggest "entities" in the first bullet and "functional entities" in the second bullet should be changed to "registered entities". This will make them consistent with one another and the function model. The "Reliability Functional Model Technical Document" describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.
Response: R3 & R5: The SDT disagrees. By utilizing the results of the required Operational Planning Analysis, the Transmission Operator will know what other entities are known or expected to be affected. Striking the clause will not provide clarity but open up other questions. No change made. R5: The use of the term 'significant' would not provide any additional clarity as it is still an objective term open to interpretation. Merely striking the examples does not provide additional clarity either as it leaves the situation completely open to interpretation. The SDT believes that including the examples is the best way to go. Any auditor trying to use a 1 MW change on a 10,000 MW system will be hard-pressed to justify their actions. No change made. R10: The SDT disagrees. If the commenter accepts that directing others to act is the same as taking action itself, then the SDT asserts that Requirement R10 is perfectly in line with Requirement R11. No change made. Data retention: The SDT believes that by incorporating a reference to the requirements in question within the data retention language that the concern expressed by the commenter is not an issue. No change made. CEA: The SDT is using language here that has been utilized in multiple standards projects to date and was supplied by staff as accepted language. Furthermore, the SDT does not believe that the suggested changes will provided any additional clarity. No change made.		
Progress Energy	Yes	: Progress Energy requests the removal of the word "identified" in association with Reliability Directive in all Requirements and Measures. Communications between Transmission Operators and other functional

Organization	Yes or No	Question 1 Comment
		entities already require 3-part communications; having to state 'This is a Reliability Directive' to each entity and receive confirmation of that back from each entity, especially across a fleet of Generator Operators and LSEs, could add unnecessary time before action is taken. Entities should always assume that each directive being given to them is a Reliability Directive and respond accordingly. R1 would read "and Load-Serving Entity shall comply with each Reliability Directive issued by its Transmission Operator...".
Response: The SDT believes that it is imperative that each Reliability Directive be identified as such. The SDT refers the commenter to proposed COM-002-3 where it is clearly stated that each Reliability Directive must be identified as such. The SDT does not believe that such communication will delay a response. No change made.		
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Southern Company Services, Inc.	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Southern Company Generation	Affirmative	Please see comments submitted by Antonio Grayson on behalf of each part of Southern Company.
Mississippi Power	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Southern Company	Yes	R3. The requirement is worded such that it implies that the Transmission Operator has a Transmission Operator. We suggest adding the word "other" so that it reads "shall inform its Reliability Coordinator and other Transmission Operator(s)...."

Organization	Yes or No	Question 1 Comment
		R5. We recommend the following word changes:Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations that are known or expected to result in an Adverse Reliability Impact on those their respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations may include are relay or equipment failures, and changes in generation, Transmission, or Load.
Response: The SDT does not see any additional clarity with the suggested changes. No change made.		
Occidental Chemical	Affirmative	See Ingleside Cogeneration LP comment form
Ingleside Cogeneration LP	Yes	As a GO/GOP, Ingleside Cogeneration LP is subject only to TOP-001-2 R1 and R2, related to compliance with a Reliability Directive. We believe that the SDT has captured the appropriate circumstances for when a Reliability Directive is issued and identified - and the circumstances under which it may be not be possible to accommodate one. Furthermore, we agree with the language added to the corresponding Measures (M1 and M2) specifically allowing an attestation to be supplied to a CEA if a Reliability Directive was not received during the compliance time frame.
ComEd	Affirmative	Voted
Electric Reliability Council of Texas, Inc.	Affirmative	ERCOT supports the SDT's modifications.
Nebraska Public Power District	Affirmative	NPPD joins comments submitted by the Southwest Power Pool (SPP).
Southwest Power Pool Regional Entity	Yes	

Organization	Yes or No	Question 1 Comment
Imperial Irrigation District (IID)	Yes	
Dominion	Yes	
Luminant	Yes	
SPP Standards Review Group	Yes	
Arizona Public Service Company	Yes	
Independent Electricity System Operator	Yes	
City of Austin dba Austin Energy	Yes	
Liberty Electric Power LLC	Yes	
NV Energy	Yes	
American transmission Company	Yes	
FirstEnergy Corp	Yes	
Essential Power, LLC	Yes	
NextEra Energy, Inc.	Yes	
Cowlitz County PUD	Yes	
Response: Thank you for your support.		

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The majority of the comments received were requesting clarification or suggesting semantic changes. Clarifications have been provided but the semantic changes were not seen as providing any additional clarity to the standard.

Organization	Yes or No	Question 2 Comment
AEP Service Corp.; American Electric Power	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Bonneville Power Administration	Negative	Comments submitted separately.
Duke Energy	Negative	Comments submitted.
Duke Energy Carolina	Negative	Comments submitted
Florida Municipal Power Agency	Negative	Please see FMPA comments submitted separately.
Lakeland Electric	Negative	"Please see FMPA comments submitted separately"
Response: Thank you for submitting comments. Your comments are addressed below.		
MidAmerican Energy Co.	Negative	TOP-002 R2 uses the same vague language as TOP-001 R8. The wording "special subset of SOLs as defined by the TOP" needs to be added. Otherwise NERC and regional auditors will apply the wording broadly when the intent was for a specific subset of SOLs defined by the TOP. Also see the NSRF comments

Organization	Yes or No	Question 2 Comment
Response: The wording of TOP-002-3, Requirement R2 is intentionally identical with that in TOP-001-2 to ensure consistency on terminology across the standards. The SDT does not believe these words are vague but believes they provide a specific reference for Transmission Operators to work with while allowing those Transmission Operators flexibility in operations. No change made.		
Seattle City Light	Negative	2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 No Comments: R2, calls for TOP to have a plan to prevent exceeding SOLs of facilities identified in TOP-001-2 as “supporting reliability internal to its Transmission Operator Area.” This could cause TOPs to be in conflict with no remedy when there are competing transmission paths or facilities supporting internal reliability. R3 just requires TOP to notify all registered entities identified in R2, but again there is no requirement for those entities to comply with the plan. Is that all that is intended? This Standard could also be very difficult to comply with due to the data retention policy which requires maintaining six months worth of data for system analysis. The system studies requires huge amount of data and to maintain that amount of data for 6 months could be very expensive and complicated. Please reconsider cost vs. benefit of the data retention requirement. 6. If you have any other comments on these standards that you have not already provided in response to the prior questions, please provide them here. Comments: Seattle City Light supports the efforts of the Real Time Operations Standards Drafting Team and approves of the direction proposed in these new TOP Standards. TOP-001 in particular clarifies the definition of Reliability Directive and provides straightforward requirements for reporting outages of relay and communication equipment. We are prepared to vote “affirmative” for all of the new TOP Standards

Organization	Yes or No	Question 2 Comment
		of Project 2007-03 once details as discussed above are addressed and resolved.
Response: R2: The SDT fails to see how the phrase in question will cause conflicts for the Transmission Operator. If there are competing solutions it is the obligation of the Transmission Operator to find the best solution for the reliability of the system. That is true today and it will not change in the future due to this phrasing. All this phrasing does is give the Transmission Operator another tool, namely elevating the status of certain SOLs, to come up with the best solution for reliability. No change made. R3: The SDT believes that Requirement R3 is informational in nature as it is in the planning horizon. Actual 'orders' to implement the plan will be issued at a later time by the Transmission Operator and are covered in other standards such as the proposed TOP-001-2. The SDT believes that the notification in this requirement will provide an opportunity for entities to comment on the plan and thus for the Transmission Operator to fine tune its plan. No change made. Data retention: In this day of cheap storage capability, the SDT does not believe that it will be an onerous burden to retain 6 months of analysis. This amount of storage is also consistent with guidelines provided by NERC staff. No change made.		
Westar Energy	Negative	SDT has not adequately addressed previous comments.
Response: The SDT points Westar to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
Florida Municipal Power Pool	Affirmative	See FMPA comments
Florida Municipal Power Agency	No	The existing TOP-002-2 requires that both the BA and TOP perform current day, next day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document

Organization	Yes or No	Question 2 Comment
		also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". FMPA is aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. IN the meantime, the new TOP standards should include operational planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. FMPA believes that both current-day and seasonal remain important, to cover changes from yesterday’s plan (e.g., unplanned outages that have occurred since yesterday’s plan), and to coordinate planned outages seasonally. R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2.
City of Vero	No	The existing TOP-002-2 requires that both the BA and TOP perform current day, next

Organization	Yes or No	Question 2 Comment
		day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". FMPA is aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. IN the meantime, the new TOP standards should include operational planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. FMPA believes that both current-day and seasonal remain important, to cover changes from yesterday’s plan (e.g., unplanned outages that have occurred since yesterday’s plan), and to coordinate planned outages seasonally. R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an

Organization	Yes or No	Question 2 Comment
		SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2.
Beaches Energy Services of theCity of Jacksonville Beach, Florida	No	The existing TOP-002-2 requires that both the BA and TOP perform current day, next day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". We are aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. In the meantime, the new TOP standards should include operational

Organization	Yes or No	Question 2 Comment
		planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. We believe that both current-day and seasonal remain important, to cover changes from yesterday's plan (e.g., unplanned outages that have occurred since yesterday's plan), and to coordinate planned outages seasonally. R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2.
Response: The Balancing Authority has one role: To balance Load and resources. A key component of this role is to be able to recover from events that cause imbalance. The commenter intermingles the obligation of the Load-Serving Entity with that of the Balancing Authority. The SDT believes that in order for a Balancing Authority to comply with CPS and DCS and the requirements for emergency plans in EOP that they must plan and therefore a separate requirement is not needed and would actually represent double jeopardy. BAL-001-0.1a, BAL-002-1, EOP-001-0b, EOP-002-3, and EOP-003-1 cover these issues for the Balancing Authority. The standard has not eliminated other planning periods as Operational Planning Analysis covers all of the periods cited. What it does do is mandate a next-day analysis. Current day will be handled in Real-time operations and thus isn't needed in this planning environment. The SDT believes that longer term studies will be run by entities on an as needed basis but that requirements are only necessary for next-day. No change made. Stability Limit is a defined term in the NERC Glossary. IROLs and SOLs represent only part of what the Operational Planning Analysis (OPA) is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. No change made.		

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	No	BPA appreciates the drafting team's response to our previous comments and recommends additional clarification: Previous Comments: Given the potential uncertainty regarding how many day ahead studies may be required, BPA suggests adding more clarity to the standard TOP-002-3 to address. BPA recognizes that various regions experience peak operations at different times of the day, anticipated generation patterns shift over the course of the day; and transmission facilities of service start and stop times associated with planned maintenance and construction work at various times throughout the day. Hence, due to these multiple shifts in forecast system conditions, it is unclear whether more than one study is required to meet the requirements of this standard. Additional New Comments:Many entities tend to perform system studies more than one day ahead. Please specify the threshold at which a prior study would have to be updated to meet the next day study requirement. BPA suggests alternate language for the requirement ...something along the lines of ... An entity or TOP may perform a study more than one day in advance; they shall update the study if system conditions (such as line outages, etc.) changed such that there was more than a 5% change in the system operating limit, thereby requiring the need to rerun the study.
Response: There is no mandate in the standard regarding how many studies need to be performed. The requirement is for a valid analysis. If one study can get that done, then one study is sufficient. If conditions change, the SDT expects that the Transmission Operator will conduct another study to analyze the new conditions as the 'old' analysis would no longer be valid. The SDT believes that there is no single value applicable on a continent-wide basis that could be placed in a requirement and that the Transmission Operator is best suited to determine when a new analysis needs to be performed. No change made.		
Consumers Energy	No	This standard gives the TOP more direct authority than is in the MISO process today. The market has means to accommodate this operation. In R3, this may conflict with the present logic our TOP follows concerning their operation in the area of communicating conditions to Generation Operators and other Market Participants. We do not support this standard as written.

Organization	Yes or No	Question 2 Comment
Response: The commenter has failed to provide details on how Requirement R3 conflicts with policy so the SDT is unable to comment in that regard. However, the SDT wishes to point out that Requirement R3 does not require that the entire plan be sent to all entities – just that entity's role in the plan. No change made.		
Southwest Transmission Cooperative, Inc.	Affirmative	We generally agree with the changes to the standard. However, we have identified the following concerns. TOP-001-2 R8 implies the Transmission Operator must look for SOLs that are not IROLs in its Operational Planning Analysis that must be completed per TOP-002-3 R1. There is no such requirement in TOP-002-3 R1 or any other requirement that compels a Transmission Operator to look for these SOLs that are not IROLs. Thus, the SDT needs to clarify if a Transmission Operator is required to look for these SOLs that are not IROLs in the Operational Planning Analyses and why they are not referenced in TOP-003-2 R1. If the SDT did not intend for a Transmission Operator to be required to look for these SOLs that are not IROLs, then it needs to refine TOP-001-2 R8 to be clear that the Transmission Operator may not have a need for these SOLs that are not IROLs. TOP- 002-3 R2 further confuses the situation by referring to the SOLs that are not IROLs that are identified in TOP-002-3 R1 rather than TOP-001-2 R8. Under the Compliance Enforcement Authority section, we suggest "entities" in the first bullet and "functional entities" in the second bullet should be changed to "registered entities". This will make them consistent with one another and the function model. The "Reliability Functional Model Technical Document" describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity. We disagree with the inclusion of voice recordings as an example of the type of evidence that might be retained for TOP-002-3. Operational Planning Analyses are typically conducted in a back office where communications would not be recorded. This might create the impression that there is now a requirement to record such

Organization	Yes or No	Question 2 Comment
		conversations. Recording of these conversations could mute much of the discussion that occurs among personnel performing these studies and working to resolve issues identified in them. Also, the three months retention period is not consistent with the change made to the retention period in TOP-001-2. It was changed to 90 days for voice recordings.
ACES Power Marketing	No	We generally agree with the changes to the standard. However, we have identified the following concerns. TOP-001-2 R8 implies the Transmission Operator must look for SOLs that are not IROLs in its Operational Planning Analysis that must be completed per TOP-002-3 R1. There is no such requirement in TOP-002-3 R1 or any other requirement that compels a Transmission Operator to look for these SOLs that are not IROLs. Thus, the SDT needs to clarify if a Transmission Operator is required to look for these SOLs that are not IROLs in the Operational Planning Analyses and why they are not referenced in TOP-003-2 R1. If the SDT did not intend for a Transmission Operator to be required to look for these SOLs that are not IROLs, then it needs to refine TOP-001-2 R8 to be clear that the Transmission Operator may not have a need for these SOLs that are not IROLs. TOP-002-3 R2 further confuses the situation by referring to the SOLs that are not IROLs that are identified in TOP-002-3 R1 rather than TOP-001-2 R8. Under the Compliance Enforcement Authority section, we suggest “entities” in the first bullet and “functional entities” in the second bullet should be changed to “registered entities”. This will make them consistent with one another and the function model. The “Reliability Functional Model Technical Document” describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity. We disagree with the inclusion of voice recordings as an example of the type of evidence that might be retained for TOP-002-3. Operational Planning Analyses are typically conducted in a back office where communications would not be recorded.

Organization	Yes or No	Question 2 Comment
		This might create the impression that there is now a requirement to record such conversations. Recording of these conversations could mute much of the discussion that occurs among personnel performing these studies and working to resolve issues identified in them. Also, the three months retention period is not consistent with the change made to the retention period in TOP-001-2. It was changed to 90 days for voice recordings.
Brazos Electric Power Cooperative, Inc.	Negative	Additional clarification is necessary that warrants our negative vote. See the issues raised in the comments by ACES Power Marketing.
Response: The SDT expects the SOLs in question to come out of the analysis performed in Requirement R1 but does not believe that the requirement needs to explicitly tell the Transmission Operator that. It is part and parcel of the analysis function. No change made. CEA: The SDT is using language here that has been utilized in multiple standards projects to date and was supplied by NERC staff as accepted language. Furthermore, the SDT does not believe that the suggested changes will provided any additional clarity. No change made. Since this is a notification requirement, voice recordings are an appropriate type of evidence.		
AEP	No	In the previous comment period, AEP requested clarification on whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumed this was based on Real Time Flow, but we encouraged the drafting team to provide clarifying language to make it more clear to the reader. The drafting team responded by noting that “TOP-002-3 is about Operations Planning, thus it cannot be addressing actual Real-time flow” and “It addresses those flows contained in the Operational Planning Analysis (OPA) and the assessment thereof.” However, no such clarifying language was added to the standard. As stated in our response to Question #1, industry has provided comments to standard drafting teams in an effort to help avoid CANs, Interpretation Requests, and to increase the consistency of interpretation by both CEA’s and industry. And once again, while the team provided insight in their comments, the resulting lack of changes to the standard

Organization	Yes or No	Question 2 Comment
		still leave unnecessary ambiguity that could be easily addressed. Ambiguity of any kind deters from, rather than promotes, the reliability of the BES. Until such clarification is added to the standard itself, AEP cannot support the drafting team's efforts in revising TOP-002-3. Rather than using terms such as "real-time flow", we recommend using "projected post-contingency" and "projected pre-contingency".
Response: The SDT believes that the definition of IROL speaks for itself and therefore that no further explanation is required within the standard. No change made. The SDT sees no additional clarity from the suggested change. No change made.		
Duke Energy	No	o R2 - Consistent with our comment above on TOP-001-2 Requirement R8, the phrase "supporting its internal area reliability" should be further clarified in some way. Also, change the phrase "as supporting" to "in support of".
Response: The SDT believes that the Transmission Operator is uniquely qualified to determine such SOLs and that no further clarification is necessary. No change made. The SDT sees no additional clarity being provided by the suggested wording changes. No change made.		
Oncor Electric Delivery	No	Oncor agrees that the Operational Analysis Plan should be properly communicated, but that it should not be the role of the Transmission Operator to determine who is or who is not NERC Registered.
Response: NERC registered entities can easily be looked up and the SDT does not believe this is an onerous burden. This requirement as worded currently relieves the Transmission Operator of the obligation to notify entities that are not registered with NERC. No change made.		
Southern Company	No	R3- Southern understands the intent of this requirement is to notify all registered

Organization	Yes or No	Question 2 Comment
		entities that may be affected by a mitigation plan for the next day so they can be prepared to respond. However, in some cases like the one shown in the example below, it is unreasonable to expect the TOP to notify every GOP that could be re-dispatched. Requiring this would actually put the system at risk as the TOP would be focused on notifying GOPs inside its TOP area and potentially outside its TOP area and not focused on operating the system.Southern suggests that the requirement be changed to state that the TOP will notify “other TOP’s and associated RC(s) associated with actions in the plan(s)” in a similar manner that other TOPs and RCs are notified in the proposed TOP-001-2, R3 and R5. If that is unacceptable to the SDT then it is suggested at a minimum that “all NERC registered entities” be clarified with the addition of the word “explicitly” just prior to” identified in the plan(s)”.Example: An SOL is identified in the Operational Analysis for the next day from R2. The plan to mitigate this SOL is to call an IDC-TLR. The level of the TLR may or may not reach level 5. If the TLR reaches level 5 many generators will be required to be re-dispatched inside and outside of the TOPs area. This requirement will require the Transmission Operator to notify every Generator Operator that could possibly be re-dispatched for a TLR-5.Another concern with having the TOP notify all entities (which would include those outside their area) is the added FERC Standards of Conduct risk that the NERC standard is forcing the TOP to assume. For example, notification may go to a GOP which also performs market functions about which the TOP is unaware. In communicating the plan to the GOP, the TOP may inadvertently communicate non-public transmission information in violation of the Standards of Conduct. If communications is limited to external entities that are TOP and RC, this risk is eliminated and the communication to the GOP will take place by its native TOP - which should be familiar with any Standards of Conduct restrictions on communication to the GOP.

Response: The SDT believes that all entities that have a role in the plan need to be notified or the eventual implementation of the plan could be compromised. The requirement only stipulates that an entity receive notice of their role in the plan so there should be no fear of inadvertently providing sensitive information to an entity that shouldn’t have such information. No change made.

Organization	Yes or No	Question 2 Comment
ReliabilityFirst Corporation	Abstain	ReliabilityFirst abstains and offers the same comments as submitted via the previous comment posting period.
Response: The SDT points RFC to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
American Transmission Company, LLC	Affirmative	Comments submitted.
Florida Power Corporation	Affirmative	comments submitted
FirstEnergy Energy; FirstEnergy Solutions	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Manitoba Hydro	Affirmative	Please see comments submitted by Joe Petaski (Manitoba Hydro)
Mississippi Power	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Progress Energy; Progress Energy Carolinas	Affirmative	"comments submitted"
Southern Company Generation; Southern Company Services, Inc.	Affirmative	Please see comments submitted by Antonio Grayson on behalf of each part of Southern Company.
Ohio Edison Company	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.

Organization	Yes or No	Question 2 Comment
Response: Thank you for submitting comments. Your comments are addressed below.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power; Tacoma Public Utilities	Affirmative	The term “anticipated … Contingency event conditions” in R1. is not a NERC defined term and could be interpreted as requiring analysis of all contingencies including extreme events. The requirement should clarify if it only applies to certain types such as category P1 or whether each TO can independently select which types of contingencies they anticipate. One suggested form or rewording the requirement could be: R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal conditions and TPL-001-2 category P1 Single contingencies.
Response: The SDT believes that more than just single Contingencies need to be studied in order to have a viable plan. Extreme events are a separate item in the planning standards and would not be included here. No change made.		
Sacramento Municipal Utility District	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of "bulk power system" to "Bulk Electric System" would be changed on certain pertinent standards. This appears to be such a case.
Response: Neither of those terms is used within this standard. No change made.		
City of Austin dba Austin Energy	Yes	TOP-002-3, R1TOP-002-3, R1 states “Each Transmission Operator shall have an Operational Planning Analysis ...” and the mapping document says that this requirement “is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator.” As such, Austin Energy suggests that the language in TOP-002-3, R1 be changed from “... shall have an Operational Planning Analysis ...” to “... shall perform an Operational Planning Analysis ....” This language matches IRO-008-1, R1 and better aligns with Measure 1 for TOP-002-3.

Organization	Yes or No	Question 2 Comment
Response: The language in Requirement R1 is intentional to allow for the use of a previously completed Operational Planning Analysis if it is still viable. No change made.		
Dominion	Yes	TOP-002-3 M2 should be updated to reflect the changes made in R2 (as suggested below).M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis. VSLs R2 (page 5 redline version) Severe Column should be updated to reflect the changes made in R2 (as suggested below).The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.
Response: The SDT sees no additional clarity being provided with the suggested change. No change made.		
Manitoba Hydro	Yes	Section 1.3 Data Retention - For consistency with TOP-001-2, the retention period for voice recordings in TOP-002-3 should be changed from 3 months to ‘ninety calendar days’.
Response: Your suggested change has been made.		
Progress Energy	Yes	Please change the R2 VSL from “supporting its internal area reliability” to “supporting reliability internal to its Transmission Operator Area...”.

Organization	Yes or No	Question 2 Comment
Response: The SDT sees no additional clarity being provided with the suggested change. No change made.		
Idaho Power Company	Yes	I agree with the direction of the project. Consolidating all the TOP standards and eliminating the redundancy will make it much easier.
Cowlitz County PUD	Yes	This Standard is not applicable to Cowlitz PUD and the District will abstain in the ballot. However, this commenter sees no problems with the changes.
Nebraska Public Power District	Affirmative	NPPD joins comments submitted by the Southwest Power Pool (SPP).
ComEd	Affirmative	Voted
Consolidated Edison Co. of New York	Affirmative	See NPCC group comments
Electric Reliability Council of Texas, Inc.	Affirmative	ERCOT supports the SDT's modifications.
American transmission Company	Yes	
Arizona Public Service Company	Yes	
FirstEnergy Corp	Yes	
Imperial Irrigation District (IID)	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 2 Comment
Occidental Chemical	Affirmative	See Ingleside Cogeneration LP comment form
Ingleside Cogeneration LP	Yes	
ISO New England Inc	Yes	
Kansas City Power & Light	Yes	
Liberty Electric Power LLC	Yes	
Luminant	Yes	
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NSRF for LES' concerns.
Great River Energy	Affirmative	Great River Energy agrees with the comments of the MRO NSRF
MRO NSRF	Yes	
New York Independent System Operator	Yes	
NextEra Energy, Inc.	Yes	
NV Energy	Yes	
Southwest Power Pool Regional Entity	Yes	
SPP Standards Review Group	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 2 Comment
Xcel Energy	Yes	
Response: Thank you for your support.		

3. The SDT made changes to TOP-003-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The comments received requested clarification or suggested semantic changes. The SDT has provided clarifications where requested. The semantic changes were not seen as providing any additional clarity to the requirements and have not been accepted. One change was made to Requirement R2, Part 2.1 to improve consistency between the requirement and the part in response to industry comments.

Part 2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

Organization	Yes or No	Question 3 Comment
AEP Service Corp.; American Electric Power	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Cowlitz County PUD	Negative	Comment submitted.
Florida Municipal Power Agency	Negative	Please see FMPA comments submitted separately.
Kansas City Power & Light Co.	Negative	Comments and concerns with the proposed standards have been expressed within the NERC comment form
Lakeland Electric	Negative	"Please see FMPA comments submitted separately"
Omaha Public Power District	Negative	OPPD supports MRO and SPP RTO comments. Please see comments from Doug Peterchuck.
Response: Thank you for submitting comments. Your comments are addressed below.		
City of Garland	Negative	The requirements should be written such that they will support VSL levels of Lower,

Organization	Yes or No	Question 3 Comment
		Moderate, and High - not Severe only for R5. It should take minimal requirement sentence strucuring to allow for all VSL levels to be assigned
Response: The SDT believes that the severity of not fulfilling an entity's obligations for this requirement warrant a single severe VSL. No change made.		
East Kentucky Power Coop.	Negative	The standard as proposed does not appear to comply with the stated intent of Project 2007-03, that being: "The industry needs clearer, unambiguous and enforceable standards in order to effectively operate the Bulk Electric System." Not only are the changes to TOP-003 as vague—or ambiguous--if not more so than the previous TOP-003-1 standard, the requirements do not provide for any consistency between companies. For example, who between two parties determines, or in the case of an inability to reach agreement, who is responsible for arbitrating an agreement when two neighboring entities are attempting to establish a "mutually agreeable format". Resolution could be problematic when required changes to a format between entities A and B would require format changes between entities A and C, A and D, and A and E, and would potentially require entity A to maintain several different format standards to meet the requirements for coordination between entities B, C, D, and E. Many items previously in TOP-003-1 appear to have been completely abandoned in lieu of much less prescriptive specifications in TOP-003-2. For example, clear provisions regarding timing of data availability listed in TOP-003-1 are not specified in any form in TOP-003-2 other than to require that entities needing to share data essentially "work it out amongst themselves". The standard needs to better guide entities in regard to the type of data—at a minimum—they SHOULD be requesting and obtaining. Alternately, such format specifications should be left to the authority of the RC to coordinate among TO/BA entities for which they are responsible.

Organization	Yes or No	Question 3 Comment
Response: The SDT asserts that existing arbitration procedures can, and will be, used to resolve conflicts. No change made. Format agreements between A and B will not affect formats between A and C and vice versa. It is true that a Transmission Operator or Balancing Authority may need to support multiple formats but that is no different than it is today. No change made. The SDT believes that the requirements are sufficiently prescriptive without inhibiting needed flexibility in devising solutions. Mutual agreement amongst affected entities is a better solution in the long run than trying to force a one-size-fits-all approach to the problem. No change made. The concept of the data specification is that the Transmission Operator and Balancing Authority are in the best position to determine what data they need to perform their duties. This is in alignment with the approved IRO standards for the Reliability Coordinator. No change made. The Reliability Coordinator will be the final arbitrator on disputes but the SDT believes that it would be detrimental to the work of the Reliability Coordinator for them to be involved in each and every agreement if it isn't necessary. No change made.		
INTELLIBIND	Negative	The Requirements are confusing and refer to other requiremtns. The original concept was that requirments shall stand alone, and not be dependent on other requirments or standards. Violation of R1 or R2 will cascade to addtional violations based on the structure of the Standard. These issues should be repaired as a part of this revision.
Response: The requirements do stand alone and are not dependent on other requirements. There are simple references to other requirements in Requirement R5 but no dependence. Each requirement stands alone and the VSLs follow suit so there are no cascading violations. No change made.		
Seattle City Light	Negative	While the idea of making each BA and TOP formally outline a data specification for all the information it needs to perform its Operational Planning Analysis is a worthy concept, the requirements in this Standard for evidence and data retention are onerous. Specifically the requirement to retain all electronic or hard copies of data transmittals or retain attestations from all receiving entities would require a tremendous amount of resources to be compliant. It may also be technically impossible to comply with these requirements because the data specifications developed individually by each entity may not be compatible with each other. The

Organization	Yes or No	Question 3 Comment
		formats and periodicity of data collected by each entity may not be compatible with the specifications and it could be impossible to comply with these requests without major changes to the infrastructure. As an alternative, most of the NERC registered entities are currently required to provide that data to their Reliability Coordinators (RC) using the specifications already developed by the RCs and that data could be used by the TOPs and BAs to perform their functions. Seattle City Light supports the efforts of the Real Time Operations Standards Drafting Team and approves of the direction proposed in these new TOP Standards. We are prepared to vote “affirmative” once details as discussed above are addressed and resolved.
Response: The SDT believes that it is counter-productive to involve the Reliability Coordinator in data transfers that are simply pass-through transfers and also believes that not all of the data required by a Transmission Operator or Balancing Authority will be available from the Reliability Coordinator in every instance. There is nothing in the standard that requires the retention of every data transmittal. Once an entity has provided evidence that they are supplying the data, the measure has been fulfilled. This should not be an onerous task. No change made.		
Westar Energy	Negative	SDT has not adequately addressed previous comments.
Response: The SDT points Westar to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
AEP	No	In the previous comment period, AEP suggested that R5 be modified so that it does not unintentionally create an edict to provide “any data” to parties simply because R5 could be interpreted as allowing requests of any kind. The SDT responded by stating that “Requirement R5 is bound by the constraints of Requirements R1 and R2 so that not just any information can be requested.” AEP does not see any explicit constraints specified in R1 or R2, and even if constraints were noted there, see nothing that would indicate those constraints would also apply to R5. At the most, the only possible constraint could be the “mutually agreeable format”, however that would seem to provide no bounds or constraints on the kind or amount of data being requested. We suggest providing further clarification that what has been mutually

Organization	Yes or No	Question 3 Comment
		agreed to by the parties involved, goes beyond simply the format of the data. In addition, it needs to be made clear that those constraints also apply to R5. Until such clarification is added to the standard itself, AEP cannot support the drafting team's efforts in revising TOP-003-2.
Response: Requirement R1 clearly limits the data to that needed to support Operational Planning Analysis and Real-time monitoring. The SDT believes that this sufficiently limits the type and amount of data that can be requested. Requirement R5 is tied to the data specifications delivered in Requirements R3 and R4 so the limitations carry through. No change made.		
Florida Municipal Power Pool	Affirmative	See FMPA comments
Beaches Energy Services of theCity of Jacksonville Beach, Florida	No	Related to the BA performing a day-ahead plan discussed in FMPA's response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.
City of Vero	No	Related to the BA performing a day-ahead plan discussed in FMPA's response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead

Organization	Yes or No	Question 3 Comment
		as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.
Florida Municipal Power Agency	No	Related to the BA performing a day-ahead plan discussed in FMPA's response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.

Response: The Balancing Authority has one role: To balance Load and resources. A key component of this role is to be able to recover

Organization	Yes or No	Question 3 Comment
from events that cause imbalance. The commenter intermingles the obligation of the Load-Serving Entity with that of the Balancing Authority. The SDT believes that in order for a Balancing Authority to comply with CPS and DCS and the requirements for emergency plans in EOP that they must plan and therefore a separate requirement is not needed and would actually represent double jeopardy. BAL-001-0.1a, BAL-002-1, EOP-001-0b, EOP-002-3, and EOP-003-1 cover these issues for the BA. The data specification concept has already been approved by FERC for Reliability Coordinators in the IRO standards. No change made.		
Consumers Energy	No	The standard as written is more vague than the current TOP-003. It follows the logic of IRO-010 and talks about specification documents instead of actions that need to be taken. We do not support this standard as written.
Response: The data specification concept has already been approved by FERC for Reliability Coordinators in the IRO standards. No change made.		
Cowlitz County PUD	No	After reviewing the industry comments submitted, Cowlitz is respectfully perplexed why comments were not addressed related to lack of recourse the receiving entity of a data specification has if the data specification is unreasonable. The data specification receiving entity must have some recourse to appeal unreasonable obligation requirements short of appealing a violation finding through the RE/NERC/FERC or ultimately a court of law. Due to the undefined nature of what constitutes a reasonable data specification document other than a “mutually agreeable format,” the risk of capricious dictatorial demands having no reliability return is high. The usage of “format” can only encompass the organization, plan, and style of the data to be submitted; this can’t be used to limit data submittal to that which is available at a rate of transmittal which is possible. Cowlitz can’t find a remedy for requirement R5 without allowing for some risk of entity intransigent behavior leading to RE or ERO intervention. However, there are current standards that allow, but limit, this risk by defining allowable exceptions. Examples which include such exceptions to requirements are “unless such actions would violate safety...,” contained in several standards; and “unless it provides a reliability reason

Organization	Yes or No	Question 3 Comment
		to the requestor...," contained in Standard IRO-006-5. Cowlitz suggests the following exemptions: Unless data or information is not available without installation of additional equipment, or can't be reasonably available due to existing equipment limitations, available personnel limitations, or unexpected equipment failure.
Response: The SDT asserts that there are existing arbitration processes that entities can employ short of going to NERC, FERC, or courts. No change made.		
Idaho Power Company	No	TOP-003 will require that we create a list of data necessary to complete our operational planning analysis. Currently I don't think we have a good process for doing analysis so defining the data required may be difficult.
Response: Compliance with this requirement will be mandatory, resulting in the need for the list mentioned by the commenter.		
Liberty Electric Power LLC	No	Multiple entities commented in the prior round that the standard would expose RE's to violation space in the event of a communications failure. Although the SDT stated in the consideration of comments that "It is not the intent of the SDT that TOP-003-2 penalizes entities for communication errors. The intent is to have the data communications established.", the plain language of the standard is in conflict with this position. The standard as written states a RE "shall satisfy the obligations of the documented specifications for data." Among the specifications of real time data requests are the periodicity of the submission. For example, PJM in Manual 14D, Generator Operational Requirements, states "All data items, regardless of type, are collected and disseminated at the same 2-second rate. Instantaneous MW and MVAR information is collected on the same data scan as Integrated MWh and MVARh." If a RE has a loss of their RTU, they will have failed to "satisfy the obligations of the documented specifications for data", and be exposed to a potential violation.If the intent of the SDT is as stated in the previous consideration of comments, there must be some language to that effect added to the standard. In R1, adding a bullet 1.21 "an alternative format for use in the event of interruption of the mutually agreed format" would close the hole in the language as written and

Organization	Yes or No	Question 3 Comment
		satisfy the stated objections.
Response: Loss of an RTU or other communication problems are covered in the COM standards. This requirement is solely for the set up required to fulfill an entity's data obligations. No change made.		
Luminant Energy; Luminant Generation Company LLC	Negative	See comments submitted by Luminant.
Luminant	No	TOP-003-2 as currently written does not provide any recourse for the entity receiving a data request if that entity feels the data request is unreasonable either in content or timing or if the entity does not have the data available to submit. As such I would recommend modify R5 as follows:R5. Each......shall satisfy the obligations of the documented specification for data. R5.1. If the entity receiving the data request cannot provide the requested data either in content or timing then the entity receiving the data request shall notify the requesting entity and provide a reason for not providing the data.
Response: The SDT asserts that there are existing arbitration processes that entities can employ short of going to NERC, FERC, or courts. No change made.		
Great River Energy	Affirmative	Great River Energy agrees with the comments of the MRO NSRF
American transmission Company	No	Requirement R3 and R4 should specify which entities are required to respond to data requests. For example, a TOP in Indiana who sends a request to a TOP in Wisconsin; should the TOP in Wisconsin be required to respond. ATC recommends that the term "contiguous entity" be referenced and added to the requirements.+
MidAmerican Energy	No	See the NSRF comments
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NSRF for LES' concerns.

Organization	Yes or No	Question 3 Comment
Muscatine Power & Water	Negative	Please see comments submitted by the MRO NSRF
MRO NSRF	No	Requirement R3, and R4 must specify which entities are required to respond to data requests. For example should a TOP in Indiana send a request to a TOP in Wisconsin, must it be complied with. Suggest a, “contiguous entity” reference.Requirements R1 and R3 are very vague and need to add more specificity similar to that from existing standard TOP-005 which includes specific guidelines.
Response: The SDT believes that data requirements may go beyond contiguous entities and that any entity receiving a data specification is obligated to respond. No change made.		
City Utilities of Springfield, Missouri	Negative	City Utilities of Springfield, MO supports the comments from SPP.
Southwest Power Pool Regional Entity	No	SPP RE does not believe TOP-003-2 addresses the requirements in PRC-001.
Response: Without specific comments, the SDT is unable to respond as the SDT believes the requirements are met.		
Texas Reliability Entity	No	1) Overall, this change to TOP-003-2 will cause differences in what each TOP/BA thinks it needs in terms of data, which will be difficult to audit. There should be a minimum set of data that the TOP/BA should address (especially when removing more specific Requirements such as those that are deleted from PRC-001-1.) For example, if a TOP or BA decides not to monitor its SPSs, which is currently required by PRC-001-1, there will be no repercussions from a compliance standpoint, but an impact to monitoring the state of reliability will occur. 2) R1: We suggest adding “analysis functions” after Operational Planning Analysis to fully capture performance requirements for a TOP during Real-Time. 3) R2: We suggest adding “Operational Planning Analyses” in front of “analysis functions”. The Operational Planning Analysis, by definition, includes “Expected

Organization	Yes or No	Question 3 Comment
		system conditions such as load forecast(s), generation output levels . . .," which relate to the Real Power balance requirement that the BA must comply with. A BA should also create a documented specification for the data necessary for it to perform an Operational Planning Analysis, which may include development of integrated operational plans, acquiring reliability-related services from Generator Operators, providing generation dispatch to the Reliability Coordinator, and other responsibilities as dictated by the Functional Model. 4) R3 We suggest adding "analysis functions" after Operational Planning Analysis to fully capture performance requirements for a TOP during Real-Time. 5) R4: We suggest "Operational Planning Analyses" in front of "analysis functions" to be consistent with our comment that R2 should require "Operational Planning Analysis" data in the BA's data specification. 6) R3 and R4: What is the required time frame required for the TOP and BA to distribute changes to its data specification? We suggest adding a sentence that the TOP or BA must distribute its data specification within 30 calendar days of creation or revision. 7) R5: What is the required time frame for an Entity to satisfy the obligations of the data specification? None is specified. We suggest a time frame of 30 calendar days from the date of receipt to comply with changes to data specifications. 8) The VRF and VSL justification document was inconsistent and unconvincing in several respects related to TOP-003-2 R2. That should be revisited after the requirements are firmed up.

Response: 1. The SDT believes that each Transmission Operator and Balancing Authority will have different requirements for data. That is one of the reasons for the data specification concept. Any omissions in the data specification will be filtered out by the inability of the Transmission Operator or Balancing Authority to fulfill their obligations and should therefore be quickly rectified. Any penalties associated with such omission would thus be picked up in the other standards associated with those duties. No change made.

Organization	Yes or No	Question 3 Comment
2. The SDT sees no additional clarity being provided with the suggested change. No change made. 3. Requirement R1 previously included both the Transmission Operator and Balancing Authority. However, multiple comments in previous postings pointed out that Balancing Authorities do not perform Operational Planning Analyses and thus the requirement was split as it is now shown. No change made. 4. The SDT sees no additional clarity being provided with the suggested change. No change made. 5. Balancing Authorities do not perform Operational Planning Analyses. No change made. 6. The SDT sees no additional clarity being provided with the suggested change. The timeframe is essentially determined in Requirements R1, Part 1.4 and R2, Part 2.4. No change made. 7. Requirements R1, Part 1.4 and R2, Part 2.4 identify the timeframe involved. No change made. 8. Without specific comments, the SDT is unable to respond.		
ReliabilityFirst Corporation	Abstain	ReliabilityFirst abstains and offers the same comments as submitted via the previous comment posting period.
Response: The SDT points RFC to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
PNGC Group Comments		Comments: In addition to the same Applicability argument we made in Question 1 for TOP-001-2, the PNGC comment group has a couple of minor issues with TOP-003-2:1. We question the Violation Risk Factor (VRF) of "Medium" for R5. R1-4 have VRFs of "Low" so the "Medium" designation for R5 seems unwarranted. If the SDT views the failure of TOPs and BAs to distribute data requests to other entities in an agreeable format as a "Low" risk, then the failure of those other entities to respond to issued data requests should also be a "Low" risk. We believe R1-5 should all have a "Low" VRF. 2. R1 and R2 require the BA and TOP create a documented specification for data needed to perform analysis functions and Real-time monitoring. We question R1.2 and R2.2: "A mutually agreeable format." There absolutely should be a mutually

Organization	Yes or No	Question 3 Comment
		agreeable format for the data but the standard doesn't define how that is to be accomplished. It seems to us that the TOP and BA will just issue the directive without consultation and that violation of R1.2 and R2.2 by the TOP or BA is unenforceable. We suggest expanding M1 and M2 to include acknowledgement by entities that are the subject of requests. The acknowledgment should include that the request was received and the data format is agreed to.
Response: Requirements R1 through R4 all represent actions that are taking place 'ahead' of time. Therefore, there is some flexibility regarding them. Requirement R5 is the actual supply of data and there is no slack involved. No change made.		
Kansas City Power & Light		There is no reliability purpose served by an Entity developing and posting specifications of data needed to perform its Operational Planning Analysis and Real-time monitoring. The only reliability action that matters is the request for data specific to other Entities in order to perform analysis and monitor operating conditions. These requirements would be more effective if they targeted the following principles:1. Identify the data needed to perform analysis and effectively monitor operating conditions,2. Identify the Entities that may have data useful to support analysis and monitoring operating conditions and, 3. Seek to obtain the data from other Entities by engaging the other Entities and coming to a mutual agreement regarding data exchange with the Entity. Requirement R5 does not allow for "mutual agreement" as the SDT has suggested in their response to comments from the last draft. As written, this requirement will cause an Entity that is a recipient of a request for data to fail the requirement if a mutual agreement cannot be made. The SDT further states in their response to comments that requirements R1 and R2 ensure disparity between Entities cannot occur. On the contrary, the specifications that are developed as required by these requirements lock an Entity into that specification. If another Entity cannot meet any part of the specification in a data exchange request, there is no recourse in these requirements to relax the specification. The SDT has good intentions, however, these requirements as written

Organization	Yes or No	Question 3 Comment
		do not allow for the flexibility needed in the exchange of data with other parties.
Response: The SDT disagrees. There is a definite reliability benefit to creating the data specifications as they are required in order for the Transmission Operator and Balancing Authority to obtain the data they need to fulfill their responsibilities. The recipient of the data specification must receive clear data requirements or it may fail to provide data necessary to support the reliability reason that instigated the issuance of the data specification. Requirement R5 does not include mutual agreement because that concept is covered in Requirements R1 and R2. The SDT asserts that there are existing arbitration processes that entities that provide adequate recourse if issues can't be resolved. No change made.		
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
American Transmission Company, LLC	Affirmative	Comments submitted.
Duke Energy Carolina	Affirmative	comments submitted
FirstEnergy Energy Delivery; FirstEnergy Solutions	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Manitoba Hydro	Affirmative	Please see comments submitted by Joe Petaski (Manitoba Hydro)
Mississippi Power	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
New York Independent System Operator	Affirmative	Comments have been provided
Ohio Edison Company	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional

Organization	Yes or No	Question 3 Comment
		comments and suggestions submitted through the formal comment period.
Southern Company Generation	Affirmative	Please see comments submitted by Antonio Grayson on behalf of each part of Southern Company.
Southern Company Services, Inc.	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Response: Thank you for following the instructions on submitting comments. Your comments are addressed below.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	If a Transmission Operator or a Balancing Authority is requesting data from another entity, they must demonstrate a reliability impact validating the need for the requested data.
Response: By limiting data to that specified in Requirements R1 and R2, the SDT believes that only reliability related data will be requested. No change made.		
Nebraska Public Power District	Affirmative	NPPD joins comments submitted by the Southwest Power Pool (SPP).
Southwest Power Pool, Inc.	Affirmative	We continue to disagree with the successive ballot process that forces entities to decide on a voting position concurrent with the submittal of comments on the same. NERC needs to explore other ways to expedite the voting/comment process without forcing industry to have faith that changes will be made after approval. Although SPP votes in favor of this standard, we have outstanding comments that should be addressed. We have submitttted them in the standards processs and reiterate some of them here. The Purpose Statement is too general and does not provide any direction of how the proposed standard will meet its stated intent. As written the Purpose Statement is applicable to any NERC standard that exists or can be imagined. We suggest additional wording of how this particular standard intends to do what it intends to is

Organization	Yes or No	Question 3 Comment
		needed. For example, "...through requiring all operating parties who need to take action have the knowledge and obligation to do so." Deleting the requirements from PRC-001 and including them in R1 and R2 of TOP-003-2 raises the question of what other types of data or information need to be included in the specification that do not normally come to mind when considering this type of information. To be sure that all the bases are covered, we would suggest that the SDT provide a guideline which incorporates the types of data and information they envisioned when drafting these requirements. Additionally, incorporating protective relay information in the data specifications of R1 and R2 raises the potential for auditors to question the contents of an entity's specification. Again, guidance is needed on the part of the TOP and BA in developing the specification initially. Could the SDT provide this initial guidance, or list of examples, in the form of a guideline? We have concerns with R1 and R2 being as open-ended as they are, especially since they are followed by the obligation to provide that data contained in R5. For example, how do you resolve issues when a mutual agreement cannot be reached? If an entity feels that the requestor is asking for data that goes beyond what they would reasonably need to perform their analysis, what process is used to resolve the stand-off?
Response: The SDT is a process user and does not determine the elements of the process. If the commenter has problems with the successive ballot concept, it should be directed to the NERC Standards Committee. The SDT believes that the Purpose Statement is direct and to the point and clearly identifies what is required. No change made. The SDT re-iterates its position that the Transmission Operator and Balancing Authority are the best ones to determine the contents of the data specification and that any attempt to provide a minimal list or other guidance would be short-sighted and possibly misleading. The SDT believes that an auditor can only question what is contained in the requirements and in this case that would include only the existence of the data specification and not its contents. Any omissions of data will be caught up in failures to adhere to other standards. No change made. The SDT asserts that there are existing arbitration processes that entities can employ short of going to NERC, FERC, or courts. No		

Organization	Yes or No	Question 3 Comment
change made.		
Tacoma Public Utilities	Affirmative	If a Transmission Operator or a Balancing Authority is requesting data from another entity, they must demonstrate a reliability impact validating the need for the requested data.
Response: By limiting data to that specified in Requirements R1 and R2, the SDT believes that only reliability related data will be requested.		
Brazos Electric Power Cooperative, Inc.	Negative	Additional clarification is necessary that warrants our negative vote. See the issues raised in the comments by ACES Power Marketing.
Southwest Transmission Cooperative, Inc.	Affirmative	Generally, we agree with the standard. However, we have one concern regarding the Data Retention section. The third bullet compels the Transmission Operator to retain evidence for three calendar years that it distributed its data specification. Because the data needs do not change frequently, it is possible that the Transmission Operator will have periods greater than three years in which the data specification was not updated and, thus, not communicated. What data and information would the Transmission Operator use to demonstrate compliance in this situation? Would an attestation be appropriate? If so, the measure should be updated to reflect this. All of the responses to comments regarding concerns of Requirement R5 indicate that the SDT intended for Requirement R5 to apply to the general satisfaction of the data specification and not any specific data points. However, the Data Retention section does not support this view point. It requires retention of 90 days worth of data. Normally, short periods of data are retained when they are expected to be voluminous. Thus, we assume the Data Retention section was anticipating that the actual data supplied would be retained. This seems inconsistent with the concept of generally satisfying the data specification. It would make more sense to have a statement from the Transmission Operator indicating the data specification has been satisfied or documentation of the enabling of data links to demonstrate general

Organization	Yes or No	Question 3 Comment
		satisfaction of the data requirements. Under the Compliance Enforcement Authority section, we suggest "entities" in the first bullet and "functional entities" in the second bullet should be changed to "registered entities". This will make them consistent with one another and the function model. The "Reliability Functional Model Technical Document" describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.
ACES Power Marketing	Yes	Generally, we agree with the standard. However, we have one concern regarding the Data Retention section. The third bullet compels the Transmission Operator to retain evidence for three calendar years that it distributed its data specification. Because the data needs do not change frequently, it is possible that the Transmission Operator will have periods greater than three years in which the data specification was not updated and, thus, not communicated. What data and information would the Transmission Operator use to demonstrate compliance in this situation? Would an attestation be appropriate? If so, the measure should be updated to reflect this. All of the responses to comments regarding concerns of Requirement R5 indicate that the SDT intended for Requirement R5 to apply to the general satisfaction of the data specification and not any specific data points. However, the Data Retention section does not support this view point. It requires retention of 90 days worth of data. Normally, short periods of data are retained when they are expected to be voluminous. Thus, we assume the Data Retention section was anticipating that the actual data supplied would be retained. This seems inconsistent with the concept of generally satisfying the data specification. It would make more sense to have a statement from the Transmission Operator indicating the data specification has been satisfied or documentation of the enabling of data links to demonstrate general satisfaction of the data requirements.

Organization	Yes or No	Question 3 Comment
		Under the Compliance Enforcement Authority section, we suggest "entities" in the first bullet and "functional entities" in the second bullet should be changed to "registered entities". This will make them consistent with one another and the function model. The "Reliability Functional Model Technical Document" describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.
Response: The SDT believes that data specifications will change within a 3 year period and thus the situation cited is not relevant. If by some chance the specification didn't change, there are many ways to show that and the SDT doesn't feel that this exception needs to be spelled out in the standard. No change made. Data retention for Requirement R5 does not require that all data be kept for 90 days. It states that an entity must show that they fulfilled the obligation of the requirement. One way to do that would be to keep the data but there are other ways to show it. No change made. The SDT sees no additional clarity being provided with the suggested change. No change made.		
Manitoba Hydro	Yes	R2.1 - For consistency with R2 and completeness, 'analysis functions' should be added to R2.1. Suggested wording: 'A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring'.
Response: The SDT agrees and has made conforming changes to Requirement R2, Part 2.1. **Part 2.1**. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.		
NextEra Energy, Inc.	Yes	NextEra believes additional editing is needed to provide the step-by-step clarity the proposed Reliability Standard seeks to implement. To provide more clarity, NextEra suggests that in R3, R4 and R5 be rewritten as follows: "R3. Consistent with the requirements of R1, each Transmission Operator shall distribute its request for data

Organization	Yes or No	Question 3 Comment
		to each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider that has data required to be used in the Transmission Operator's Operational Planning Analysis and Real-time monitoring process. ""R.4 Consistent with the requirements of R2, each Balancing Authority shall distribute its data request to each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider that has data required to be used in the Balancing Authority's analysis functions and Real-time monitoring process.""R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider that receives a data request pursuant to Requirement R3 or R4 shall provide the requested data."
Response: The SDT sees no additional clarity being provided with the suggested change. No change made.		
NV Energy	Yes	We see no problem with what was changed in this posting; however, please note issues raised related to TOP-003-2 in the comment submitted on Question 6.
Response: Please see response to Q6.		
Occidental Chemical	Affirmative	See Ingleside Cogeneration LP comment form
Ingleside Cogeneration LP	Yes	We are encouraged that the SDT has added a statement in M3 and M4 calling for those TOPs and BAs who post their data specifications to also electronically notify the downstream data suppliers. This is a good first step in the use of a web-based data collection process - which we hope will replace the spreadsheet-based process mostly in place today. A goal of such a system must be to consolidate all operational data requirements into a single template, so that data suppliers are not subject to redundant criteria.

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Yes	BPA is in support of this standard due to the importance of being able to receive data.
Consolidated Edison Co. of New York	Affirmative	See NPCC group comments
Electric Reliability Council of Texas, Inc.	Affirmative	ERCOT supports the SDT's modifications.
ComEd	Affirmative	Voted
Arizona Public Service Company	Yes	
City of Austin dba Austin Energy	Yes	
Dominion	Yes	
Duke Energy	Yes	
Essential Power, LLC	Yes	
FirstEnergy Corp	Yes	
Imperial Irrigation District (IID)	Yes	
Independent Electricity System Operator	Yes	
ISO New England Inc	Yes	

Organization	Yes or No	Question 3 Comment
New York Independent System Operator	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
Southern Company	Yes	
SPP Standards Review Group	Yes	
Xcel Energy	Yes	
Response: Thank you for your support.		

4. **The SDT is suggesting the retirement of three requirements in PRC-001 since those requirements deal with data handling and can now be incorporated in the data specification concept suggested for TOP-003-2. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The comments received were mainly requesting clarification or suggesting semantic changes. Clarification has been provided where necessary. The semantic changes were not seen as providing additional clarity and have not been incorporated.

One change to the standard was made due to industry comments. Section 1.2 of the Compliance Section was deleted as duplicative of Section 1.4.

Organization	Yes or No	Question 4 Comment
AEP		While AEP supports, in general, the removal of redundant requirements across standards, we do not yet agree with the proposed changes to TOP-003-2 (for the reasons provided in our response to Question #3). As such, AEP will reserve comment on any future changes that might be made to PRC-001 until further progress is made on TOP-003-2.
Response: Please see response to Q3.		
American transmission Company		ATC agrees with removing R6 from PRC-001, however ATC does not believe it is appropriately addressed in TOP-003-2. If the intent is to have SPS data as a part of a data specification, it should be stated in the requirements of TOP-003-2.
MRO NSRF		The NSRF agrees with removing R6 from PRC-001, however we do not feel it is appropriately addressed in TOP-003-2. If the intent is to have SPS data as a part of a data specification, it should be stated in the requirements of TOP-003-2.
Response: The intent of the data specification requirement concept is that the Transmission Operator and Balancing Authority will request all of the data that they need to fulfill their responsibilities. If that includes SPS data, then they will be expected to request it.		

Organization	Yes or No	Question 4 Comment
No change made.		
Florida Municipal Power Agency		Please see response to Question 6
City of Vero		Please see response to Question 6
Beaches Energy Services of theCity of Jacksonville Beach, Florida		Please see response to Question 6
Response: Please see response to Q6.		
Manitoba Hydro		Section 1.4 Compliance Monitoring and Assessment Processes - Section 1.4 should be removed as it is identical to Section 1.2 'Compliance Monitoring and Reset Time Frame'.
Response: The SDT agrees that the sections are duplicative and has deleted Section 1.2.		
Southwest Power Pool Regional Entity		SPP RE does not believe TOP-003-2 addresses the requirements in PRC-001.
Response: The SDT disagrees. The data specification is required to contain all of the information that a Transmission Operator or Balancing Authority needs to fulfill its obligations. No change made.		
SPP Standards Review Group		No (The Yes/No boxes weren't on the screen. All I got was the comment box.)Deleting the requirements from PRC-001 and including them in R1 and R2 of TOP-003-2 raises the question of what other types of data or information need to be included in the specification that do not normally come to mind when considering this type of information. To be sure that all the bases are covered, we would suggest that the SDT provide a guideline which incorporates the types of data and information they envisioned when drafting these requirements. Additionally, incorporating protective

Organization	Yes or No	Question 4 Comment
		relay information in the data specifications of R1 and R2 raises the potential for auditors to question the contents of an entity's specification. Again, guidance is needed on the part of the TOP and BA in developing the specification initially. Could the SDT provide this initial guidance, or list of examples, in the form of a guideline? Also, measures for R1 and R3 are missing.
Response: The SDT re-iterates its position that the Transmission Operator and Balancing Authority are the best ones to determine the contents of the data specification and that any attempt to provide a minimal list or other guidance would be short-sighted and possibly misleading. The SDT believes that an auditor can only question what is contained in the requirements and in this case that would include only the existence of the data specification and not its contents. Any omissions of data will be caught up in failures to adhere to other standards. No change made. The scope of the changes that the SDT was allowed to make only involved the deletion of the requirements and did not represent a revision of the standard as a whole. That will be taken up in a later project. No change made.		
NV Energy		No, we believe there may be reliability gaps introduced with the specific deletion of old R2 from PRC-001. We are concerned that the open-ended specification of required data per proposed TOP-003 R1 may not adequately cover the notification of status and conditions for certain protection systems and SPS. With the requirement R2 in place, there is no doubt about the need to make notification of these sorts of losses or status changes. Absent the requirement, it is likely that inconsistent specifications for such information by TOP's or BA's will result.
Response: The SDT disagrees. The data specification is required to contain all of the information that a Transmission Operator or Balancing Authority needs to fulfill its obligations. No change made.		
ACES Power Marketing		No. While we are supportive of the changes, they do not appear to be coordinated with the Project 2007-06 System Protection Coordination that was started recently. It appears to retain the retired requirements.
Response: The version of PRC-001 that is posted on the web site is over two years old and does not represent the current work being done with that standard. The SDT has coordinated the changes to PRC-001 with the Project 2007-06 team and the next iteration		

Organization	Yes or No	Question 4 Comment
shown by that project will not have the data requirements. No change made.		
Texas Reliability Entity		No.1) Requirements R2, R5 and R6 of PRC-001-1, which are proposed to be deleted, are not actually replaced by any new or revised requirements in other standards, resulting in reliability gaps. The PRC-001-1 requirements relate to Same-day and Real-time Operations, whereas the TOP-003-2 requirements relate only to the Operations Planning time horizon. The real-time elements of the PRC-001-1 requirements are lost. 2) R2- Removal of R2 assumes that the requirement intent will be included in TOP-003-2 R1 or R2 specification, but there is no new requirement to replace R2 of PRC-001. 3) R2 - The requirements to “take corrective action as soon as possible” are extremely important to the reliability of the system and deleting them introduces a reliability gap. In the Issues Database document there is indication that R5 of TOP-001-2 satisfies the need for corrective action as soon as possible with the following phrase “Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations.” However, the text of TOP-001-2 R5 does not actually support this approach and therefore leaves a reliability gap in the Standards. 4) Texas RE disagrees with several of the PRC-001 issues listed as complete in the Issues Database. The referenced TOP Standards are extremely limited in scope and lacking in details (especially in light of ignoring Real-Time issues) and are not considered interchangeable with the deleted PRC-001 Requirements as suggested. 5) R5- Removal of R5 assumes that the requirement intent will be included in TOP-003-2, but there is no new requirement to replace R5 of PRC-001.. R5 is related to the coordination of changes affecting protection systems of others. R5 should not be removed because it deals with coordination issues and not merely specification and provision of data. 6) R6-We object to the proposed removal of R6 because this Real-time requirement is not picked up anywhere else, and elimination of the requirement to monitor and

Organization	Yes or No	Question 4 Comment
		communicate the status of Special Protection Systems will cause a reliability gap. 7) There are no Measures for Requirements R1 and R3.
Response: 1. The SDT disagrees. TOP-003-2 sets up the transfer of Real-time information as shown in Requirements R1 and R2. No change made. 2. The data specification is required to contain all of the information that a Transmission Operator or Balancing Authority needs to fulfill its obligations. No change made. 3. Once the SDT provides notification as per TOP-001-2, Requirement R5, the SDT believes that they will be directed as to what to do. No change made. 4. Without specific comments, the SDT is unable to respond. However, the SDT disagrees that the proposed standards ignore Real-time. No change made. 5. The Transmission Operator already has the responsibility in its core set of duties to provide such coordination and the SDT believes that a separate requirement is not needed to reinforce this. No change made. 6. The SDT disagrees. The data specification is required to contain all of the information that a Transmission Operator or Balancing Authority needs to fulfill its obligations. No change made. 7. The scope of the changes that the SDT was allowed to make only involved the deletion of the requirements and did not represent a revision of the standard as a whole. That will be taken up in a later project. No change made.		
NextEra Energy, Inc.		Yes, we agree.
Liberty Electric Power LLC		Yes. Thank you to the SDT for removing these requirements.
Bonneville Power Administration		Yes, BPA is in support of the retirement of the three requirements in PRC-001 as the SDT is suggesting.
Essential Power, LLC		Yes, I support the recommendation.
Arizona Public Service		Yes, we agree with the changes the drafting team has made.

Organization	Yes or No	Question 4 Comment
Company		
Southern Company		Yes, we agree with the SDT's suggestion
City of Austin dba Austin Energy		We agree.
Imperial Irrigation District (IID)		Yes
Duke Energy		Yes
MidAmerican Energy		Yes - retire the three requiements in PRC-001
Cowlitz County PUD		Cowlitz supports the retirement.
FirstEnergy Corp		FE agrees with the changes that have been made by the drafting team.
Ingleside Cogeneration LP		Ingleside Cogeneration LP agrees that relay and equipment status can be included in a telemetry specification as part of TOP-003-2 - which is redundant with PRC-001-1 R2 and R6. Similarly, the coordination of changes in generation operating conditions such as de-ratings that could require changes in the TOP's Protection System (R5) can be captured in existing data submission vehicles that TOP-003-2 will also cover.
Oncor Electric Delivery		Agree with changes
Dominion		Agree with changes made.
Response: Thank you for your support.		

5. **The VRF, VSL, and Time Horizons are part of a non-binding poll. Please indicate whether you agree or disagree with the VRF, VSL, and Time Horizon assignments. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Several typos in the VRF/VSL justification document were pointed out by commenters and have been fixed. No other changes have been made to the VRFs or VSLs.

Organization	Yes or No	Question 5 Comment
PNGC Group Comments	No	Please see our response to Question 2.
Response: Please see response to Q2.		
AEP	No	In general, the VRFs and VSLs are too severe and punitive. Those stated for R1, R2, and R5 of TOP-001-2 are especially so, given what we see as open-endedness to what might be requested. As a result, AEP cannot support the proposed VRFs and VSLs.
Response: The SDT believes that the VRFs and VSLs follow accepted guidelines. Without any specific comments, the SDT is unable to provide specific responses. No change made.		
ACES Power Marketing	No	The Moderate and High VSLs for TOP-001-2 R3, R5, R6, and R8 incorrectly use an "or" condition when "and" is necessary to establish the range of percentages of performance. As written now, any percentage from 0 to 100% qualifies for both VSLs. The following boiler plate language that is written before the VSLs for TOP-001-2 R8 needs to be included before all sets of VSLS that give an option to use integers or percentages. Otherwise, the VSLs will overlap. It should be included before TOP-001-2 R3, R5, and R6. "For the Requirement X VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this

Organization	Yes or No	Question 5 Comment
		manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation." For the Severe VSL of TOP-002-3 R3, an extra space is needed before "15%".
Response: The SDT agrees and has made conforming changes. The second 'or' condition in the Moderate and High VSLs is now "and". The boilerplate language cited is merely an explanation of the SDT's intent. The standard has been modified to show this language for Requirements R3, R5, R6, and R8 as suggested. The SDT agrees and has corrected the typo.		
MidAmerican Energy	No	See the NSRF comments
MRO NSRF	No	TOP-001-2 The adding the language of "or 5% or less of the affected Transmission Operators, whichever is less", "or more than 5% or less than or equal to 10% of the affected Transmission Operators, whichever is less", "or more then 10% or less than or equal to 15% of the affected Transmission Operators, whichever is less", " or more than 15% of the affected Transmission Operators, whichever is less" to R3, R5, and R6 is confusing and not necessary. For example: 10 affected TOs. The lower VSL states: The TO did not inform one other TO or 5% or less of the affected TOs, whichever is less. 5% of 10 is .5 TOs which is less than 1. The percentage language should be removed. TOP-003-2 - Same issue with VSLs as with TOP-001-2. The percentage language should be removed from R3 and R4. PRC-001-2 - R1 VSL for High and Severe seem arbitrary. Not knowing limitations are not as bad as not knowing purpose? Suggest either breakdown by number of systems. Ie: did not know purpose and limitations of 1 protection scheme, etc. Or Binary. Severe - did not know purpose and limitation of protections systems in its area.
Response: The percentage language was added at the direct behest of the Quality Review Team and utilizes standard language for		

Organization	Yes or No	Question 5 Comment
this type of situation. No change made.		
Luminant	No	The VSL for TOP-003-2 R5 places a more stringent severity level on the entities receiving the data requests than it places on the entities that are responsible for creating the data requests. As such, I would suggest changing the VSL for TOP-003-2 R5 to the following:Lower: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy one of the obligations of the documented specification for data Moderate: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy two of the obligations of the documented specification for data High: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy three of the obligations of the documented specification for data Severe: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy four or more of the obligations of the documented specifications for data.
Response: The SDT sees the previous requirements in TOP-003-2 as ahead of time requirements which mean that there is some slack that can be incorporated into the deliberations without jeopardizing reliability and VSLs reflect this fact. However, Requirement R5 is about the actual data transfer and there is no room for error, thus the more stringent VSL. No change made.		
Kansas City Power & Light	No	In addition, the VSL for R5 in TOP-003 does not reflect partial efforts to exchange data by Entities.
Response: Requirement R5 is about the actual data transfer and there is no room for error, thus the more stringent VSL. No change made.		
Liberty Electric Power LLC	No	As written data transmission failures subject REs to a severe violation in R5, see Q3 response.
Response: Please see response to Q3.		
NV Energy	No	PRC-001 R1: Though this requirement does not appear to be within the scope of the

Organization	Yes or No	Question 5 Comment
		SDT's efforts in this project, we note that for R1 (familiarity of purpose and limitations of protection systems), there is no Measure in the Standard, and the VSL's appear to be quite subjective. I would like to make a specific suggestion, but cannot do so without knowing what sort of Measures are intended for this requirement. Perhaps, change the VSL language to state "Entity does not possess documentation describing purpose/limitations of its protection systems for its Operator personnel."
Response: The scope of the changes that the SDT was allowed to make only involved the deletion of the requirements and did not represent a revision of the standard as a whole. That will be taken up in a later project. No change made.		
Duke Energy	No	o TOP-001-2 VSLs should be revised consistent with our comments on the requirements. o TOP-003-2 VSLs have explanatory language on how the SDT intends the VSLs to be used. This language needs to be incorporated into the VSLs more directly, because compliance personnel will not be bound by the SDT's intent.
Response: No changes were made to the requirements as explained in Q1. No change made. The SDT believes that the VSL language is correct and will not need to be changed to reflect the explanation which will be deleted from the final draft. It was provided here for ease of reference to commenters. No change made.		
Texas Reliability Entity	No	1) VSL for TOP-001-2 R3: Operational Planning Analysis, by definition, excludes Real-Time issues such as "actual Emergencies." We suggest improving the requirement as discussed above and then making conforming revisions to this VSL. 2) VSL for TOP-001-2 R5: "When conditions permit" is subjective and ambiguous therefore consistency in auditing will not occur. Are you sure that "whichever is less" is what you mean to say here? (also applies to VSLs for R3, R6 and R8) 3) TOP-001-2 R7: VRF justification statement is incomplete ("The requirements are viewed as similar since they both refer to <missing text>") 4) TOP-001-2 R8: In the VRF justification, the text in the second and third bullets

Organization	Yes or No	Question 5 Comment
		appears to be garbled. 5) TOP-001-2 R9: We recommend this requirement be assigned a "High" VRF. Uncorrected SOL violations could cause bulk power system instability, separation, and or cascading if exacerbated in Real-Time by other SOL violations, contingencies, faults, or misoperations (and may be dependent on the SOL Methodology timing in FAC-011 and not be captured in TOP-001-2 R7). Note that the VRF justification for R10 correctly refers to a High VRF for R9. Additionally, remove the word "local" in all places used in the R9 VRF justification.
Response: 1. No changes were made to the requirement as explained in Q1. Therefore, no changes are necessary to the VSL. **2.** The SDT reviewed the indicated wording and verified that it is what was meant. As conditions permit is well accepted terminology in a situation where a hard and fast value is not possible. No change made. **3.** The SDT agrees and has corrected the text. **4.** The SDT agrees and has corrected the text. **5.** SOLs, by definition, can't cause instability, etc., and thus the VRF is correctly stated as Medium. The VRF justification document will be corrected accordingly. The SDT believes that the use of 'local' is appropriate.		
Oncor Electric Delivery	No	For TPL-001"Oncor respectfully takes the position that the proposed language in R6 will not provide a coordinated communication effort in the event of a planned outage of telemetry, control equipment and associated communication channels. The term "negatively impacted interconnected registered entities" is too broad and too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity."
Response: Please see response to Q1.		
Cowlitz County PUD	No	After reviewing the industry comments submitted, Cowlitz is respectfully perplexed

Organization	Yes or No	Question 5 Comment
		why comments were not addressed related to the VSL binary treatment of R5. A data specification document may be very complex, and the Standard does not define non-compliance other than obligations were not satisfied. One data variable missing (either accidental omission or inability to provide) can incur an immediate violation if the data specification document does not include any leniency in this regard. Further, the proposed VLS for R5 does not allow for any credit of the entity's effort in fulfilling the obligations set forth in a data specification document.
Response: The SDT disagrees. Requirement R5 is not about individual failures in communications. Please see response to Q3. No change made.		
Bonneville Power Administration		TOP-001-2 VRFs/VSLs - NO - BPA recommends a sliding scale based on duration and percentage of the SOL violation. Example: If an entity is high by 2% of the SOL for 1 minute, their VSL should be substantially lower than if they were 25% off for more than 30 minutes. Sliding scale should start at the bottom ... couple of MW for a minute ... as an example. TOP-002-3: VRFs/VSLs - NO - BPA recommends a sliding scale based on how far off the original study was from the after the fact analysis. Example: If an entity did not have a study, the penalty should be severe. If an entity did have a study, but it was only 5% off, the penalty should be less severe. TOP-003-2 VRFs/VSLs - YES - BPA is in support.
Response: The SDT understands the concept of a sliding scale that is being suggested but finds it impractical and potentially unwieldy to implement. In addition, it doesn't take into account the fact that 2% on one line in a particular location may be a more severe impact on the overall reliability of the system than 25% on another line. No change made.		
Western Eledtricity Coordinating Council	Yes	I support the language of the VSLs for the proposed standards. I also understand the logic behind the statement included above the VSLs for R8 of TOP-001 and R3 and R4 of TOP-003. However, I question whether or not it is appropriate for this type of language to appear in the VSLs. It seems that this should be handled by the Regional

Organization	Yes or No	Question 5 Comment
		Enforcement departments.
Response: That language will be removed in the final draft. No change made.		
Independent Electricity System Operator	Yes	In the Violation Severity Levels section of the standards, items that contain “whichever is less” following the “or” statement, may be difficult to interpret.As a suggestion, this could be addressed by improving the wording, providing examples or categorizing non-compliance as a percentage only (rather than a number “or” percentage, whichever is less)
Response: The percentage language was added at the direct behest of the Quality Review Team and utilizes standard language for this type of situation. No change made.		
City of Austin dba Austin Energy	Yes	The VSL for TOP-001-2, R8 includes instruction to “start with the Severe VSL first and then to work your way to the left until you find the situation that fits.” It explains that the goal is to assign a Severe VSL to a small entity who has just one affected reliability entity to inform and fails to do so. This structure usually makes sense; however, it is not applicable to R8. R8 requires the TOP to inform its RC of SOLs that have been identified as supporting reliability. The variability in the requirement is in the number of SOLs identified not in the number of registered entities to inform. The intent of being non-discriminatory by size of entity is already covered with regards to the number of SOLs identified because the VSL uses the “# SOLs or % of SOLs, whichever is less” approach, and the instruction becomes unnecessary. Austin Energy recommends that the SDT remove the instruction statement above R8.
Response: The statement will be removed in the final draft. No change made.		
Imperial Irrigation District (IID)	Yes	
Dominion	Yes	

Organization	Yes or No	Question 5 Comment
SPP Standards Review Group	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Ingleside Cogeneration LP	Yes	
Manitoba Hydro	Yes	
FirstEnergy Corp	Yes	
NextEra Energy, Inc.	Yes	
Response: Thank you for your support.		

6. **If you have any other comments on these standards that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: The SDT identified one comment on the mapping document that was corrected due to comments received to this question.

Organization	Yes or No	Question 6 Comment
AEP Marketing, AEP Service Corp.	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
American Electric Power	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Cowlitz County PUD	Negative	Comment submitted.
Duke Energy, Duke Energy Carolina	Negative	Comments submitted.
Florida Municipal Power Agency	Negative	Please see FMPA comments submitted separately.
Kansas City Power & Light Co.	Negative	Comments and concerns with the proposed standards have been expressed within the NERC comment form.
Lakeland Electric	Negative	"Please see FMPA comments submitted separately"
Luminant Energy	Negative	See comments submitted by Luminant.

Luminant Generation Company LLC	Negative	Comments submitted via NERC web comment form.
Omaha Public Power District	Negative	Please see OPPD comments from Doug Peterchuck
Progress Energy Carolinas	Negative	Comments submitted
Response: Thank you for submitting comments.		
City of Green Cove Springs	Negative	The existing TOP-001-1 R7 essentially requires communication to the RC and neighboring TOPs any time a Facility is to be switched. The new TOP-001-2 R5 will only require such communication when such switching would result in an "Adverse Reliability Impact" defined as: "The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection." This significantly reduces the requirements for communication / notification for switching Facilities. It is worthwhile to communicate switching of some Facilities whether or not they would result in an "Adverse Reliability Impact". Suggest rephrasing to something like any unplanned switching of Facilities not "noticed" through data provision of TOP-003-2. With the number of human error events that have occurred, we should not be reducing the communication / notification requirements. R8 is not needed since it is already covered in FAC-014-2 R5.2. As a result, R9, R10 and R11 ought to be modified to refer to FAC-014-2 rather than R8.
Response: R7: The SDT believes that notification for any switching event is contrary to good operating practice as it would load up the message queue with unnecessary information and could lead to an operator missing an important message within a group of unneeded messages. TOP-003-2 allows for an entity to request reliability-based information from another entity so they may include status on any piece of equipment that may possibly effect its operations. Therefore, the SDT does not believe that a reliability gap has been created. No change made. R8: The SDT asserts that there are subtle differences in TOP-001-2 and FAC-014-2 that the commenter is missing. FAC-014-2 provides a simple list of SOLs while TOP-001-2 is looking at particular SOLs that need special treatment. Therefore, there is no redundancy. No change made.		

City of Green Cove Springs	Negative	The existing TOP-002-2 requires that both the BA and TOP perform current day, next day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". We are aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. IN the meantime, the new TOP standards should include operational planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. we believes that both current-day and seasonal remain important, to cover changes from yesterday’s plan (e.g., unplanned outages that have occurred since yesterday’s plan), and to coordinate planned outages seasonally.

Response: The Balancing Authority has one role - to balance Load and resources. A key component of this role is to be able to recover from events that cause imbalance. The commenter intermingles the obligation of the Load-Serving Entity with that of the Balancing Authority. The SDT believes that in order for a Balancing Authority to comply with CPS and DCS and the requirements for emergency plans in EOP standards that they must plan and therefore a separate requirement is not needed and would actually represent double jeopardy. BAL-001-0.1a, BAL-002-1, EOP-001-0b, EOP-002-3, and EOP-003-1 cover these issues for the Balancing Authority. The standard has not eliminated other planning periods as Operational Planning Analysis covers all of the periods cited. What it does do is mandate a next-day analysis. Current day will be handled in Real-time operations and thus isn't needed in this planning environment. The SDT believes that longer term studies will be run by entities on an as needed basis but that requirements are only necessary for next-day. No change made.		
City of Green Cove Springs	Negative	R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2. Related to the BA performing a day-ahead plan discussed in FMPA's response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.

Response: Stability Limit is a defined term in the NERC Glossary. IROLs and SOLs represent only part of what the Operational Planning Analysis (OPA) is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. No change made. The SDT agrees and has made conforming changes to Requirement R2, Part2.1. **Part 2.1**. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring. The data specification concept has already been approved by FERC for Reliability Coordinators in the IRO standards. No change made.		
City of Green Cove Springs	Negative	While we agrees with a results-based approach to standards, it seems to us that there have been a number of human-error based problems that justify agreed upon protocols and procedures being covered by the standards. Hence, TOP-004 R6, which requires development of formal policies and procedures among neighboring TOPs should not be eliminated from the standards. On the Mapping Document, TOP-004-2 R5, on the discussion that the requirement be deleted, the document says that the TOP does not have the authority to unilaterally separate without the approval of the RC. FMPA believes that they do if there is an imminent threat (e.g., the exceptions to IRO-001-2 of “unless such actions would violate safety, equipment, or regulatory or statutory requirements”). So, while FMPA agrees that the requirement can be deleted, the reason for the deletion does not seem accurate.
Response: TOP-004-2, Requirement R6 has been superseded by the NERC Reliability Standards taken as a whole. Examples of such would be the proposed TOP-001-2. The SDT agrees and has updated the mapping document accordingly.		
City of Garland	Negative	R5 VSL levels should have low, moderate, and high - not just severe

Response: As explained in Q5, there is no room for error in Requirement R5 and thus it has been assigned a binary VSL. No change made.		
Commonwealth of Massachusetts Department of Public Utilities	Negative	o There is use of the term “Reliability Directive” in the standard which is currently and formally under development as part of another project. The posting states that this definition was agreed to by all affected project teams using it, however if the other project team formally charged with this definition’s development, changes it, then this standard and perhaps others, will have to be revisited. Bringing these standards forward seems inefficient and problematic for many. o Also in Requirement 8 there was an issue expressed by one RSC member that System Operating Limits are local limits and should not be subject of part of the NERC standards and the requirement as written creates a “subset” of SOLs that affect reliability. This could create an overly complicated standard and could lead to compliance difficulties.
Response: Please see response to identical comments in Q1.		
Detroit Edison Company	Negative	R3- The sentence should read “... inform its Reliability Coordinator and other Transmission Operator(s), ...” The word other is missing in the current draft. R6- The statement “... negatively impacted interconnected NERC registered entities...” is to vague. This could be an easy trip up during an audit. M6- same as R6- The statement “... negatively impacted interconnected NERC registered entities...” is to vague. VSLs- R6- The statement “... negatively impacted interconnected NERC registered entities...” is to vague.
Response: Please see response to identical comments in Q1.		

East Kentucky Power Coop.	Negative	The standard as proposed does not appear to comply with the stated intent of Project 2007-03, that being: "The industry needs clearer, unambiguous and enforceable standards in order to effectively operate the Bulk Electric System." Not only are the changes to TOP-003 as vague-or ambiguous--if not more so than the previous TOP-003-1 standard, the requirements do not provide for any consistency between companies. For example, who between two parties determines, or in the case of an inability to reach agreement, who is responsible for arbitrating an agreement when two neighboring entities are attempting to establish a "mutually agreeable format". Resolution could be problematic when required changes to a format between entities A and B would require format changes between entities A and C, A and D, and A and E, and would potentially require entity A to maintain several different format standards to meet the requirements for coordination between entities B, C, D, and E. Many items previously in TOP-003-1 appear to have been completely abandoned in lieu of much less prescriptive specifications in TOP-003-2. For example, clear provisions regarding timing of data availability listed in TOP-003-1 are not specified in any form in TOP-003-2 other than to require that entities needing to share data essentially "work it out amongst themselves". The standard needs to better guide entities in regard to the type of data-at a minimum-they SHOULD be requesting and obtaining. Alternately, such format specifications should be left to the authority of the RC to coordinate among TO/BA entities for which they are responsible.
Response: Please see response to identical comment in Q3.		
INTELLIBIND	Negative	There should either be a description of what the specific vote is for, or a link to the information for each vote if you want to encourage affirmative voting.
Response: Your comment will be passed on to staff for consideration in future postings.		
National Association of Regulatory Utility Commissioners	Negative	Given the standard uses the term Reliability Directive as a defined term but is not proposing to define the term in this standard for adoption in the glossary, it is inappropriate to finalize this standard.

Response: Please see response to Q1.		
Oncor Electric Delivery	Negative	Oncor believes that the Reliability Coordinator is in the best position to determine who the negatively impacted interconnected registered entities are and to effectively coordinate communication efforts after receiving the initial planned outage request from the originating entity. In addition, the term “negatively impacted interconnected registered entities” is too broad and too subjective. As a result, we recommend R6 be revised to: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
Response: Please see response to identical comment in Q1.		
ReliabilityFirst Corporation	Negative	ReliabilityFirst votes in the negative and offers the same comments as submitted via the previous comment posting period.
Response: Without specific comments, the SDT is unable to respond other than to point to previous posting responses.		
Santee Cooper	Negative	The implementation date should be at least twelve months to be consistent with TOP-001-2 and TOP-002-3. What was the rationale of reducing the implementation time from twenty-four months to ten months?
Response: The implementation date was reduced due to multiple comments in the previous posting as commenters felt that the proposed standards reflected what was already being done and would not incorporate much change. The ten month implementation period was intended to allow time for dissemination of the data specification prior to the other changes taking effect (the standards with a 12 month implementation period.)		

Seattle City Light	Negative	While the idea of making each BA and TOP formally outline a data specification for all the information it needs to perform its Operational Planning Analysis is a worthy concept, the requirements in this Standard for evidence and data retention are onerous. Specifically the requirement to retain all electronic or hard copies of data transmittals or retain attestations from all receiving entities would require a tremendous amount of resources to be compliant. It may also be technically impossible to comply with these requirements because the data specifications developed individually by each entity may not be compatible with each other. The formats and periodicity of data collected by each entity may not be compatible with the specifications and it could be impossible to comply with these requests without major changes to the infrastructure. As an alternative, most of the NERC registered entities are currently required to provide that data to their Reliability Coordinators (RC) using the specifications already developed by the RCs and that data could be used by the TOPs and BAs to perform their functions. Seattle City Light supports the efforts of the Real Time Operations Standards Drafting Team and approves of the direction proposed in these new TOP Standards. We are prepared to vote “affirmative” once details as discussed above are addressed and resolved.
Response: Please see response to identical comment in Q3.		
Southwest Transmission Cooperative, Inc.	Negative	The Moderate and High VSLs for TOP- 001-2 R3, R5, R6, and R8 incorrectly use an “or” condition when “and” is necessary to establish the range of percentages of performance. As written now, any percentage from 0 to 100% qualifies for both VSLs “For the Requirement X VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.” For the Severe VSL of TOP-002-3 R3, an extra space is needed before “15%”.
Response: Please see response to identical comment in Q5.		

Western Electricity Coordinating Council	Abstain	I agree with the language of the VSLs for TOP-003-2. I also understand the logic behind the statement included above the VSLs for R3 and R4. However, I question whether or not it is appropriate for this type of language to appear in the VSLs. Is seems that this should be handled by the Regional Enforcement departements.
Response: The language will be removed from the final drafts. No change made.		
Mississippi Power	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Georgia Power Company	Affirmative	See comments submitted by Antonio Grayson.
Bonneville Power Administration	Affirmative	Please see BPA's submitted comments
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Southern Company Generation	Affirmative	Please see comments submitted by Antonio Grayson on behalf of each part of Southern Company.
Response: Thank you for submitting comments.		
Nebraska Public Power District	Affirmative	NPPD joins comments submitted by the Southwest Power Pool (SPP).

Southwest Power Pool, Inc.	Affirmative	We continue to disagree with the successive ballot process that forces entities to decide on a voting position concurrent with the submittal of comments on the same. NERC needs to explore other ways to expedite the voting/comment process without forcing industry to have faith that changes will be made after approval. Although SPP votes in favor of this standard, we have outstanding comments that should be addressed. We have submittted them in the standards processs and reiterate some of them here. The Purpose Statement is too general and does not provide any direction of how the proposed standard will meet its stated intent. As written the Purpose Statement is applicable to any NERC standard that exists or can be imagined. We suggest additional wording of how this particular standard intends to do what it intends to is needed. For example, "...by requiring applicable entities to have the data necessary to perform reliability analyses and real-time monitoring.’
Response: Please see response to identical comment in previous questions.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	If a Transmission Operator or a Balancing Authority is requesting data from another entity, they must demonstrate a reliability impact validating the need for the requested data.
Response: Please see response to identical comment in Q3.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	We would like to request that specific definitions are included for the individual time horizons. We suggest the following potential definitions: 1. Same Day Operations - Routine actions required within the time frame of a day, but not real-time. 2. Real-time Operations - Actions required within one hour or less to preserve the reliability of the bulk electric system. 3. Operations Assessment - Follow-up evaluations and reporting of real-time operations.
Response: The latest set of approved Time Horizon classifications is posted on the Reliability Standards Resources Web Page.		
Electric Reliability Council of Texas, Inc.	Affirmative	ERCOT supports the SDT’s modifications.

Response: Thank you for your support.

END OF REPORT

Exhibit E

Analysis of VRFs and VSLs

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-03 Real-time Operations

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001-2 – Transmission Operations, TOP-002-3 – Operations Planning, and TOP-003-2 – Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in TOP-001-2, TOP-002-3, TOP-003-2:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eleven requirements in TOP-001-2. None of the eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, R4, R7, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1.1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Not informing a Transmission Operator of the inability to perform a Reliability Directive could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render emergency assistance could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R6 has been assigned a Medium VRF and is the replacement for proposed TOP-003-1, Requirement R3 which was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or cascading failures

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to operating within the IROL.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R7 mandates that entities operate within each identified IROL and its associated IROL T_v. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R8 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC’s Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. TOP-001-2, Requirement R9 mandates that entities operate within each identified local SOL. Since local SOLs in Requirement R9, by definition, can’t cause bulk power system instability, separation, or cascading this requirement was assigned a Medium VRF.
- FERC’s Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC’s Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, Requirements R7 and R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator’s understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, Requirements R7, R9, and R11 and this requirement is a simple notification requirement for informational purposes only. Therefore, bulk power system instability, separation, or cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.
- FERC’s Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R11:

- FERC’s Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC’s Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. It is also

similar to proposed TOP-001-2, Requirement R7 which has been assigned a High VRF. Therefore, there is consistency among Reliability Standards.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities act or direct others to act to mitigate the magnitude and duration of exceeding an IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

There are three requirements in TOP-002-3. All of the requirements were assigned a Medium VRF.

VRF for TOP-002-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-008-1 that is also assigned a Medium VRF. The requirements are viewed as similar since they both refer to preparing an Operational Planning Analysis: IRO-008-1 for a Reliability Coordinator, and TOP-002-3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R1, contains only one objective; therefore, only one VRF was assigned.

VRF for TOP-002-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R2 is similar in scope to approved IRO-009-1, Requirement R1, which applies to the Reliability Coordinator, while this requirement applies to the Transmission Operator. That requirement was assigned a medium VRF, as has this requirement, so there is consistency among the reliability standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or cascading failures; therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R2, contains only one objective; therefore, only one VRF was assigned.

VRF for TOP-002-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R3 is similar to approved IRO-008-1, Requirement R3, the only difference being that the IRO standards refer to the Reliability Coordinator while the TOP standards are for the Transmission Operator. IRO-008-1, Requirement R3, is assigned a Medium VRF, which is consistent with the assignment for TOP-002-3, Requirement R3.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of their roles in mitigating potential problems does not, in and of itself, lead to bulk power system instability, separation or cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

There are five requirements in TOP-003-2. Four of the five requirements were assigned a "Lower" VRF, -Requirements R1, R2, R3, and R4. Requirement R5 was assigned a "Medium" VRF.

VRF for TOP-003-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements, so only one VRF was assigned; therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among reliability standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is also assigned a Lower VRF. The requirements are viewed as similar since they both refer to data specifications: IRO-010-1a for a Reliability Coordinator, and TOP-003-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or cascading failures; therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R1, contains only one objective; therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1a that is assigned a Lower VRF. The requirements are viewed as similar since they both refer to data specifications: IRO-010-1a for a Reliability Coordinator, and TOP-003-2 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or cascading failures; therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R2, contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Lower VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1a for a Reliability Coordinator and TOP-003-2, Requirement R3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or cascading failures; therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R3, contains only one objective; therefore, only one VRF was assigned.

VRF for TOP-003-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1a that is assigned a Lower VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1a for a Reliability Coordinator, and TOP-003-2 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system, so this requirement, in and of itself, is administrative in nature and does not directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or cascading failures; therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R4, contains only one objective; therefore, only one VRF was assigned.

VRF for TOP-003-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned, so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1a that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: IRO-010-1 for a Reliability Coordinator, and TOP-003-2 for a Transmission Operator and Balancing Authority.

- FERC’s Guideline 4 — Consistency with NERC’s Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system, and will not lead to bulk power system instability, separation, or cascading failures. However, it greatly increases the likelihood of such problems and, therefore, this requirement is assigned a Medium VRF.
- FERC’s Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R5, has only one objective; therefore, only one VRF was assigned.

Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-3, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance. The performance or product measured has significant value, as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance, or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement, or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of noncompliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of noncompliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of noncompliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation, per day basis is the "default" for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved IRO-001-1.1, Requirement R8. That VSL has a Moderate violation for not complying with the Reliability Coordinator's directive for a valid reason but not informing the Reliability Coordinator of this fact. It then goes on to establish a Severe VSL for not complying with the directive. The SDT found little reason to separate out a Moderate VSL for not informing	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		the Transmission Operator. Whether it was for a valid reason or not, the consequences of the Transmission Operator not being aware of the fact that the directive was not being followed are potentially catastrophic. Therefore, the SDT has proposed only a Severe VSL and this VSL I smore stringent than the VSL cited. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1.1a, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-004-2, Requirement R1. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

TOP-002-3 R1	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved IRO-008-1, Requirement R1. That VSL is not binary as is the one proposed for this requirement. It proposes a graduated situation based on a number of days missing from the analysis. In looking at the VSL for this requirement, the SDT decided that it was an all or nothing situation – one either did the proper analysis or it didn't.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-002-3 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The requirement is similar to IRO-009-1, Requirement R1, which has a binary VSL (Severe only). The VSL for this requirement is also binary (Severe only). Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-002-3 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	TOP-002-3, Requirement R3, is similar to approved IRO-008-1, Requirement R3. The VSLs in that standard present a graded approach, as does this proposal. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1a, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-010-1a, Requirement R3. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

Exhibit F

Summary and Record of Development of Proposed Reliability Standard

Exhibit F

Summary of Development
Authorization, Posting, and Balloting History

On March 15, 2007, NERC received, and the Standards Committee accepted, a standards authorization request ("SAR") for Project 2007-03: Real-time Operations. The SAR was posted for two industry comment periods and then approved by the Standards Committee on November 1, 2007 for standard development.

The assigned standard drafting team posted the draft standard for a 45-day industry comment period from October 7, 2008 to November 20, 2008. In response, there were more than 26 sets of comments, including comments from more than 90 different people from approximately 50 companies representing 9 of the 10 Industry Segments. Comments mainly addressed the following issues:

- Deletion of redundant requirements and un-measurable terms
- The twenty-four month Implementation Plan,
- Consolidation of the eight existing TOP standards to three standards,
- Adopting a revised approach to operating within System Operating Limits (SOLs), and
- Deletion of certain core certification level requirements.

The standard drafting team revised the draft standards accordingly and re-posted for industry comment from April 7, 2009 to May 7, 2009. There were 37 sets of comments, including comments from more than 130 different people from over 45 companies representing all 10 Industry Segments. Comments received were mainly focused on support for providing emergency assistance, the need to coordinate operations, operating within a certain subset of SOLs, emphasizing 'what' is to be done as opposed to 'how' to do it, and the lack of need for a country-wide advance notice for planned outages.

The standard drafting team again revised the draft standards to accommodate industry concerns and re-posted them between August 25, 2009 and September 24, 2009. In response to this posting, there were 26 sets of comments, including comments from more than 80 different people from over 45 companies representing 9 of the 10 Industry Segments. Comments addressed the proposal to remove Balancing Authorities from the requirement dealing with the issuance of Reliability Directives and numerous requests for language clarification.

The fourth draft of the standards was posted from August 4, 2010 through September 3, 2010. There were comments from more than 34 different people from approximately 34 companies representing 7 of the 10 Industry Segments. Based on stakeholder comments, the standard drafting team made several clarifications to the requirements language. The standard drafting team did not believe that the changes were significant and requested approval from the Standards Committee to move to the ballot process.

During the development process, the standard drafting team faced several key decision points:

- The existing Reliability Standards for transmission operations were spread over eight different standards. The standard drafting team decided to incorporate all of the necessary requirements in three cohesive, comprehensive Reliability Standards.
- The existing Reliability Standards contained a number of redundancies and elements that were part of the core certification for Transmission Operators.

The standard drafting team eliminated these requirements wherever possible so that the revised standards addressed true reliability needs.

- The existing standards contained a number of 'how' requirements rather than instructing entities on 'what' to do. The standard drafting team eliminated the prescriptive requirements dictating how something be done and refocused the standards on achieving a specific result.
- The existing Reliability Standards mixed responsibilities for functional entities within the TOP family of standards. This made it difficult for entities to sort out who was responsible for the requirements. The standard drafting team reviewed existing standards and eliminated this confusion through cooperation with other standards projects working on requirements for Reliability Coordinators and by identifying what actual functional entity was truly responsible for the requirements within the TOP family of standards. The result is that the TOP family of standards now applies almost exclusively to the Transmission Operator, and the proposed IRO Reliability Standards filed concurrently with this petition apply almost exclusively to the Reliability Coordinator.
- The standard drafting team moved data exchange requirements to a data specification approach similar to the one approved by the Commission for the Reliability Coordinator in the IRO Reliability Standards.
- The standard drafting team raised the bar on system performance by mandating that all IROLs be resolved within the IROL T_v which is a significant increase in performance over the existing Reliability Standards.

- The standard drafting team worked with industry through the comment periods on adopting an approach for operating within a subset of SOLs that more closely aligns with the original Operating Guidelines.

NERC posted the proposed TOP Reliability Standards for a fifth time from April 26, 2011 to June 9, 2011, while conducting an initial ballot in parallel with this posting from May 31, 2011 through June 9, 2011. With an 88.47 percent quorum participating in the ballot, the proposed Reliability Standards achieved a weighted segment vote of 48.64 percent approval. The standard drafting team addressed all of the ballot comments and made several changes to the standards as a result.

There were 4 main themes to the comments supplied with the initial balloting:

1. Clarifying the language on Reliability Directives
2. Replacing the 30 minute SOL limit with adherence to Facility Ratings and Stability criteria
3. Clarifying the entities involved in operations planning activities
4. Clarifying the language for the data specifications

Due to the number of comments and subsequent changes to the proposed standards, the standard drafting team decided to move to another successive ballot.

The standard drafting team posted its Consideration of Comments report to the initial ballot comments as part of a concurrent posting/successive balloting period from December 14, 2011 through January 12, 2012. During this posting, each of the Reliability Standards were voted separately. TOP-001-2 had an 82.04 percent quorum participating in the ballot, and achieved a weighted segment vote of 59.93 percent approval. TOP-002-3 had an 82.04 percent quorum participating in the ballot, and achieved a weighted segment vote of 77.08 percent approval. TOP-003-2 had an 82.04 percent quorum participating in the ballot, and achieved a weighted segment vote of 78.95 percent approval.

TOP-001-2 required another successive ballot due to its failure to receive approval by the required margin. While TOP-003-2 had passed its successive ballot, the standard drafting team added the Distribution Provider to the standard due to industry comments. This amounted to a substantive change to the standard and required it to go back to a successive ballot. TOP-002-3 passed its ballot but the effective date of the standard was changed which required TOP-002-3 also move to a successive ballot.

The main themes addressed by the standard drafting team were:

- The need for clarifying language to allow for multiple Transmission Operators (TOP-001-2)
- Clarifying the term 'internal area reliability' by changing to 'internal to its Transmission Operator Area' (TOP-001-2)
- The need for semantic changes to several requirements (TOP-001-2)
- Changes to the VSLs for Requirements R1, R3, R5, and R10 (TOP-001-2)
- Adding the Distribution Provider as an applicable entity (TOP-003-2)
- Adding analysis functions to the Balancing Authority tasks (TOP-003-2)
- Changing the VSLs for Requirements R1, R2, R3, and R4 (TOP-003-2)

The standard drafting team posted its Consideration of Comments report to the first successive ballot comments as part of a concurrent posting/successive balloting period from March 22, 2012 through April 20, 2012. Once again, each of the applicable Reliability Standards was voted separately. TOP-001-2 had a 77.48 percent quorum participating in the ballot, and achieved a weighted segment vote of 75.42 percent approval. TOP-002-3 had a 77.21

percent quorum participating in the ballot, and achieved a weighted segment vote of 87.42 percent approval. TOP-003-2 had a 77.48 percent quorum participating in the ballot, and achieved a weighted segment vote of 79.98 percent approval.

NERC conducted the recirculation ballot from April 27, 2012 to May 6, 2012. The proposed Reliability Standards achieved the required two-thirds weighted segment vote and at least a 75 percent quorum of the ballot pool. TOP-001-2 achieved a quorum of 79.36 percent and an approval rating of 76.84 percent. TOP-002-3 achieved a quorum of 79.36 percent with an approval of 88.11 percent. TOP-003-2 reached a quorum of 79.36 percent and an approval rate of 80.79 percent.

During the course of the project, the standard drafting team addressed several contentious issues:

- Communication protocols: The standard drafting team revised the TOP standards to specifically address only those requirements for responding to Reliability Directives. The standard drafting team also decided that the revised definition of Reliability Directive being created in Project 2006-06 was sufficient for the needs of the TOP standards. The standard drafting team determined to remove all other communication protocols from the TOP standards to allow standard drafting teams focusing on the COM family of standards to cover all other necessary communication requirements.
- The proper handling of IROLs and SOLs: In the course of their deliberations, the standard drafting team began to look closely at the requirements around SOLs and IROLs to make certain that they accurately reflected what was needed for the reliability of the Bulk Electric System.

- Handling deliverability issues in operations planning: Power must always be deliverable to Load. There was some confusion in the past on how this deliverability was being handled in operations planning. The standard drafting team clarified this issue by tying the operations planning process to a defined activity, Operational Planning Analysis (OPA), which requires an entity to consider Contingencies and to observe all applicable limits. When all power inputs and Loads are represented in the OPA, with all applicable limits observed, energy is deliverable to Load.
- Data specification concept: The data specification approach represented a departure from the previous table-driven approach that was in existence. This caused some apprehension at first but over time the standard drafting team was able to answer industry questions and concerns. The approach was further validated when the Commission accepted a similar data specification approach for approved IRO-010-1a. The data specification requirements in TOP-003-2 are modeled after IRO-010-1a.

Minority issues expressed during the project were as follows:

- Some commenters asked for a formal definition of this term. The standard drafting team determined that the Transmission Operator should have some degree of freedom in this determination and that they are best suited to determine what affects its internal area. Therefore, the best approach is to leave the term as is and not to constrain the Transmission Operator to specific definition. This way, each situation can be determined on its own merits and the responsibility for correctly assigning SOLs to the list rests solely with the individual Transmission

Operator. Furthermore, the individual Transmission Operator is free to develop its own definition.

- Questions arose about the role of the Balancing Authority in the actions described in the revised TOP standards. The standard drafting team has clearly defined each element of responsibility that was previously defined for the Balancing Authority in the existing TOP standards and how it was handled in the revised TOP standards. The standard drafting team does not believe that any gaps have been created by the revisions.

The NERC Board of Trustees approved the proposed TOP Reliability Standards during its May 9, 2012 meeting.

Project 2007-03
Real-time Transmission Operations

Related Files

Status:
The NERC Board of Trustees approved Project 2007-03 at their May 9, 2012 meeting.

Purpose/Industry Need:
The industry needs clearer, unambiguous and enforceable standards in order to effectively operate the Bulk Electric System.

1. *Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.*
2. *Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.*
3. *Consider other general improvements as described in Appendix A.*
4. *This satisfies the ANSI procedure requirement for five-year review of the standards.*

Applicable Standards:

- *TOP-001-1 Reliability Responsibilities and Authorities*
- *TOP-002-2 Normal Operations Planning*
- *TOP-003-0 Planned Outage Coordination*
- *TOP-004-1 Transmission Operations*
- *TOP-005-1 Operational Reliability Information*
- *TOP-006-1 Monitoring System Conditions*
- *TOP-007-0 Reporting Sol and IROL Violations*
- *TOP-008-0 Response to Transmission Violations*
- *PER-001-0 Operating Personnel Responsibility and Authority*

Draft	Action	Dates	Results	Consideration of Comments
Draft 7 **Standards for Real-time Operations** TOP-001-2 Clean**(160)** | Redline to Last Posting**(161)**	Recirculation Ballots Info**(183)** Vote>>	04/27/12 - 05/06/12 (closed)	Summary**(184)** Ballot Results: TOP-001-2**(185)** TOP-002-3**(186)**	

TOP-002-3 Clean **(162)**| Redline to Last Posting**(163)** TOP-003-2 Clean**(164)** | Redline to Last Posting**(165)** Implementation Plan Clean **(166)** PRC-001-2 Clean **(167)**| Redline to Last Approved**(168)** **Supporting Materials:** Issues Database Clean **(169)** VRF and VSL Assignment Documentation Clean**(170)** | Redline to last posting **(171)** • PER-001-0.1 **(172)** • TOP-001-1 **(173)** • TOP-002-2a **(174)** • TOP-003-1 **(175)** • TOP-004-2 **(176)** • TOP-005-2 **(177)** • TOP-006-2 **(178)** • TOP-007-0 **(179)** • TOP-008-1 **(180)** **Mapping Document** Clean**(181)** | Redline to last posting**(182)**			TOP-003-2**(187)**	
Draft 7 **Standards for Real-time Operations** TOP-001-2	Successive	04/11/12 - 04/20/12 (closed) Non-binding Polls Extended	Summary**(152)** Full Records Successive Ballot Results:	

Clean **(123)**| Redline to last posting**(124)** TOP-002-3 Clean**(125)** | Redline to last posting**(126)** TOP-003-2 Clean **(127)**| Redline to last posting**(128)** Implementation Plan Clean**(129)** | Redline to last posting**(130)** PRC-001-2 Clean **(131**| Redline to last approved**(132)** **Supporting Materials:** Comment Form (Word)**(133** Updated 3/26/12 Issues Database Clean **(134)**| Redline to last posting**(135)** VRF and VSL Assignment Documentation Clean**(136)** | Redline to last posting**(137)** • PER-001-0.1 **(138)** • TOP-001-1 **(139)** • TOP-002-2a **(140)** • TOP-003-1 **(141)** • TOP-004-2 **(142)** • TOP-005-2 **(143)** • TOP-006-2 **(144)** • TOP-007-0 **(145)** • TOP-008-1 **(146)** **Mapping Document** Clean **(147)**| Redline to	Ballots and Non-binding VRF/VSL Polls Updated Info**(149)** Info**(150)** Vote>>	until 4/23/12	TOP-001-2(153) TOP-002-3(154) TOP-003-2(155) Non-binding Poll Results: TOP-001-2(156) TOP-003-2(157)	
	Comment Period Info**(151)** Submit Comments>>	03/22/12 - 04/20/12 (closed)	Comments Received**(158)**	Consideration of Comments**(159)**

last posting**(148)**				
Draft 6 **Standards for Real-time Operations** TOP-001-2 Clean**(87)** | Redline to last posting**(88)** TOP-002-3 Clean **(89)**| Redline to last posting**(90)** TOP-003-2 Clean**(91)** | Redline to last posting**(92)** **Supporting Material** Implementation Plan Clean **(93)**| Redline to last posting**(94)** **Issues Database** Clean **(95)**| Redline to last posting**(96)** **VRF and VSL Assignment Documentation** Clean **(97)** Redline to last posting**(98)** • PER-001-0.1 **(99)** • TOP-001-1**(100)** • TOP-002-2a**(101)** • TOP-003-1 **(102)** • TOP-004-2 **(103)** • TOP-005-2 **(104)** • TOP-006-2 **(105)** • TOP-007-0**(106)** • TOP-008-1**(107)** Comment Form (Word)**(108)**	Successive Ballots & Non-Binding Polls of VRFs and VSLs Extension Info on Non-binding Polls**(110)** Updated Info**(111)** Info**(112)** Vote>>	Successive Ballots: **01/03/12 - 01/12/12 (closed)** Non-binding Polls: **01/09/12 - 01/18/12** **Extension of non-binding poll for TOP-001-2 and TOP-003-2 until 01/19/12 (closed)**	Summary**(113** **Successive Ballot Results:** TOP-001-2**(114)** TOP-002-3**(115)** TOP-003-2**(116)** Comments Received**(117)** **Non-binding Results:** TOP-001-2**(118)** TOP-002-3**(119)** TOP-003-2**(120)**	
	Formal Comment Period Submit Comments>>	12/14/11 - 01/12/12 (closed)	Comments Received**(121)**	Consideration of Comments**(122)**

Mapping Document**(109)**				
Draft 5 Standards for Real-time Operations TOP-001-2 Clean**(59)** | Redline to last posting**(60)** TOP-002-3 Clean **(61)**| Redline to last posting**(62)** TOP-003-2 Clean **(63)**| Redline to last posting**(64)** **Supporting Material** Implementation Plan Clean **(65)**| Redline to last posting**(66)** Issues Database Clean **(67)**| Redline to last posting**(68)** VRF and VSL Assignment Documentation Clean **(69)**| Redline to last posting**(70)** • PER-001-0.1 **(71)** • TOP-001-1 **(72)** • TOP-002-2a**(73)** • TOP-003-1 **(74)** • TOP-004-2 **(75)** • TOP-005-2 **(76)** • TOP-006-2**(77)** • TOP-007-0**(78)** • TOP-008-1**(79)** Comment Form	Initial Ballot & Non-Binding Poll of VRFs and VSLs Vote>>	5/31/11 - 6/9/11 (closed)	Summary**(82)** Full Record**(83)** Non-Binding Results**(84)**	
	Join Ballot Pool>>	4/26/11 - 5/25/11 (closed)		
	Formal 45-day Comment Period Submit Comments>> Info**(81)**	4/26/11 - 6/9/11 (closed)	Comments Received**(85)**	Consideration of Comments**(86)**

(Word)(80)				
Draft 4 Standards for Real-time Operations TOP-001-2 Clean (46)| Redline to Last Posting(47) TOP-002-3 Clean(48) | Redline to Last Posting(49) TOP-003-2 Clean (50)| Redline to Last Posting(51) **Supporting Materials:** Implementation Plan(52) Issues Database(53) VRF and VSL Assignment Documentation (54) Comment Form (Word)(55)	Comment Period Submit Comments>> Info(56)	08/04/10 - 09/03/10 (closed)	Comments Received(57)	Consideration of Comments(58)
Draft 3 Standards for Real-time Operations TOP-001-2 Clean(36) | Redline to Last Posting(37) TOP-002-3 Clean (38)| Redline to Last Posting(39) TOP-003-2 Clean(40) | Redline to Last Posting(41) **Supporting Materials:**	Comment Period Info(43) Submit Comments>>	08/25/09 - 09/24/09 (closed)	Comments Received(44)	Consideration of Comments(45)

Comment Form (Word)(42)				
Standards for Real-time Operations TOP-001-2 Clean(21) | Redline(22) TOP-002-3 Clean(23) | Redline(24) TOP-003-1 Clean(25) | Redline(26) TOP-004-3 Clean(27 | Redline(28) TOP-008-1 Redline from Last Posting(29)(last posting included the wrong version of TOP-008-0) **Supporting Materials:** Comment Form (Word)(30) Implementation Plan Clean (31)| Redline(32)	Comment Period Info(33) Submit Comments>>	04/07/09 - 05/07/09 (closed)	Comments Received(34)	Consideration of Comments(35)
Standards for Real-time Operations Draft Standards TOP-001-004 Clean(14) TOP-001-008, PER-001 Redline(15) **Supporting Materials:** Comment Form	Comment Period Info(18) Submit Comments>>	10/07/08 – 11/20/08 (closed)	Comments Received(19)	Consideration of Comments(20)

(Word)**(16)** Implementation Plan**(17)** (Note: The Implementation Plan contains a mapping table with explanations as to why things have been changed.)				
Nominations for Real-time Operations Standard Drafting Team Info**(12)** Submit Nomination**(13)**		11/13/07 - 11/30/07 (closed)		
Draft 2 SAR for Real-time Operations Draft SAR Version 2 clean **(6)** | redline to last posting**(7)**	Comment Period Info**(8)** Submit Comments**(9)**	08/07/07 - 09/07/07 (closed)	Comments Received**(10)**	Consideration of Comments**(11)**
SAR for Real-time Operations Draft SAR Version 1**(1)**	Comment Period Info**(2)** Submit Comments**(3)**	05/15/07 - 06/13/07 (closed)	Comments Received**(4)**	Consideration of Comments**(5)**

Standard Authorization Request Form

Title of Proposed Standard	Real Time Operations (Project 2007-03)
Request Date	April 16, 2007

SAR Requestor Information		SAR Type (*Check a box for each one that applies.*)	
Name	Jim Case	☐	New Standard
Primary Contact	Jim Case	X	Revision to existing Standard
Telephone	870.541.3908	X	Withdrawal of existing Standard
E-mail	jcase@entergy.com	☐	Urgent Action

Purpose

Applicable Standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Industry Need

The industry needs clearer, unambiguous and enforceable standards in order to effectively operate the Bulk Electric System.

Detailed Description

The drafting team should address the following general changes:

- Adjust measures to match any changes to requirements.
- Add measures as needed to complete the alignment of measures with requirements.
- Address issues outlined in Appendix A.
- Review the industry comments provided during the Version 0 process, CESDT Project, RRSWG efforts, VRF work, etc., as outlined in Appendix B.
- Address the comments from FERC Order 693 as outlined in Appendix B.

In addition, the drafting team should consider the following specific changes in the TOP and COM standards:

- TOP-001-1:
    - Removal of R2 due to redundancy with R3. R2 largely describes an ill-defined procedure which should not be in a standard.
    - Adding the wording 'without delay' after the phrase 'shall comply' in the first sentence of R3.
    - Adding the wording 'without delay' in place of 'immediately' in all requirements where appropriate.
    - Eliminating R5 in light of possible redundancy with IROL standards.
    - Deleting the phrase 'all available' from R6.
    - Replacing 'burden' with 'adversely impact system reliability of' in R7.
    - Replacing 'generator outage' with 'generation facility' in R7.1.
    - Replacing 'at the earliest possible time' with 'without delay' in R7.3.
    - Deleting R8 as it is redundant with IROL, BAL, VAR and EOP standards.
- TOP-002-2:
    - Deleting R1 as it is redundant with TOP-008-1 R1.
    - Deleting R2 as it is simply good utility practice and not really a reliability standard.
    - Deleting R3 as it is redundant with TOP-004-1 R1.
    - Deleting R4 as it is redundant with IRO-005-2, R9.
    - Deleting R5 as it is simply good utility practice and not really a reliability standard.
    - Deleting R6 as it is redundant with BAL- 002-0, R4 and IRO-005-2, R9.
    - Deleting R7 and R9 as they are redundant with BAL-007 through -011.
    - Deleting R8, R10 and R11 as they are redundant with IRO-005-2, R9.
    - Deleting R12 as it is redundant with FAC-010 and -011.
    - Removing references to the Balancing Authority and real power output from R13 as they are contractual issues and as such can not be incorporated in a standard. The remaining language should be clarified.
    - R14 and R15 apply to the Generator Operator and as such do not belong in the TOP standards. The drafting team should look to find another place for these requirements if possible.
    - Deleting R16.2 as it is redundant with FAC-009-1.
    - Deleting R17 as it is no longer needed if the above mentioned changes are made.
    - R18 should be moved to FAC-009-1.

- Deleting R19 as it can not be measured.
- TOP-003-0:
    - The drafting team should review the 50 MW requirement in R1.1 to determine the size where a generator can have an adverse impact on the Bulk Electric System. See FAC-008-3.
    - Delete Reliability Coordinator when IRO-010-1 is placed in service.
    - Delete R1.3 as it is redundant with IRO-010, R3 as part of the over-all data specification effort.)
    - Re-wording R2 to require general coordination of all facilities that affect Bulk Electric System reliability.
    - Delete R4 in deference to the RC Project.
- TOP-004-1:
    - Delete R1 as it is redundant with IRO-009-1, R4.
    - Deleting R2 as it is simply the definition of an IROL and is redundant with FAC-010-1 and FAC-011-1...
    - Deleting R3 as it is redundant with FAC-010-1 and FAC-011-1.
    - Re-word R6 for clarity.
- TOP-005-1:
    - Deleting R1 as it is redundant with IRO-010-1.
    - Deleting R1.1 as it is redundant with IRO-010-1.
    - Deleting R2 as it is not a reliability concern.
    - Re-wording R3 to provide more clarity and simplicity.
    - Deleting R4 as it is redundant with INT-001-2, R1.
    - When IRO-010-1 becomes effective, Attachment 1 should be translated into a technical specification. It is only a partial list of required data.
- TOP-006-1:
    - Deleting R1 as it is redundant with FAC-009-1, R2.
    - Deleting the Balancing Authority from R2 as the list of items does not apply. Consider deleting the Reliability Coordinator from R2 as it is redundant with IRO-007-1, R1.
    - Moving R3 to PRC-001.
    - Deleting R4 as it is redundant with BAL-001 and -002 and is also addressed in IRO-010-1, R1 and R3.
    - Deleting R5 as (1) it is good utility practice and not a true reliability requirement or (2) provide clarification on the utilization of alarm processing and to provide definition of important deviations or (3) move the requirement to ORG-004-0.
    - Deleting R6 as it is redundant with BAL-005-0, R17.
    - R7: Consider deleting Balancing Authority as it is covered in BAL-005-0, R8. Consider deleting Reliability Coordinator as it is covered in BAL-008-1, R1.
- TOP-007-0:
    - Rewording R2 to say that the Transmission Operator shall act ‘without delay’ to return the transmission system to within IROL as soon as possible but not longer than the IROL T_v. The 30 minute time frame should be deleted as it is redundant with IRO-009-1, R2.
    - Delete R4 in deference to the RC Project.
- TOP-008-0:
    - Deleting R1 as it is redundant with TOP-007-0, R3.
    - R2: Suggested wording as follows:
        - R2a: For each IROL or SOL that is identified in advance of Real-time, the TOP shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take to prevent exceeding those IROLs or SOLs or to mitigate actual violations *(Violation Risk Factor: Medium) (Mitigation Time Horizon: Operations Planning)*

        - R2b. If the involved TOPs cannot agree on a solution or if there is a difference in derived operating limits (IROLs or SOLs), the more conservative solution or limit shall be utilized.
    - Deleting R3 as it is a local utility risk consideration and not a reliability issue as currently worded.
    - Re-wording R4 for clarity.
- COM-001-1:
    - Re-word R1 to provide clarity to terms such as 'adequate' and 'reliable'. The term 'telecommunication facilities' needs to be explicitly defined or re-worded to provide clarity.
    - Define 'internally' in R1.1.
    - Delete R1.4 on the basis that it is covered in the new definitions of 'adequate' and 'reliable'. The current phrasing could be interpreted that specific telecommunication devices must be redundant. We believe that this was not the original intent of this requirement. The intent should be to provide redundant telecommunication capability between reliability entities.
    - In R2, periodicity and type of testing, 'vital' and 'special attention' should be defined.
    - Re-word R3 to make clear that each reliability entity shall notify reliability entities to which you have a communication path prior to changes in telecommunication facilities that would affect them and to resolve any coordination issues.
    - Delete R6 as it is simply an ERO procedural issue. It is assumed that if it belongs in standards that it would be in CIP as opposed to COM. This would then cause the deletion of Attachment 1 and would remove NERC Net User Organization as an applicable entity.
- COM-002-2:
    - Delete the first sentence of R1 as it is redundant with COM-001-1 if the Generator Operator is added as an applicable entity in COM-001-1. Delete the second sentence as it is redundant with PER-003-0, R3.
    - Re-word R1.1 to provide clarity as to the definition of applicable areas. Delete the requirement for firm load shedding as it is not a reliability issue.
    - Re-word R2 to provide clarity for the terminology 'clear, concise and definitive'. The use of scripts is a possible solution.

Remove applicability and all references to TOP in PER-001-0 due to redundancy with TOP-001-1, R1 with the ultimate goal to eliminate PER-001-0.

There is an industry need to retain good utility practice information that may be deleted from standards requirements. Any requirements so deleted should be considered for movement into appropriate guides or reference documents.

Note that Appendix B is an informative attachment that contains material that should be addressed in the standards revision process. It should not be considered to contain mandatory changes to the standard.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
X	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
X	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
X	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.
	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
BAL-001	Real Power Balancing Control Performance
BAL-002	Disturbance Control Performance
BAL-005	Automatic Generation Control
BAL-007	Balance of Resources and Demand
BAL-008	Frequency and Area Control Error
BAL-009	Actions to Return Frequency to within FTL
BAL-010	Frequency Bias Settings
BAL-011	Frequency Limits
FAC-008	Facility Ratings Methodology
FAC-009	Establish and Communicate Facility Ratings
FAC-010	System Operating Limits Methodology for the Planning Horizon
FAC-011	System Operating Limits Methodology for the Operations Horizon
INT-002	Interchange Transaction Tag Communication and Reliability Assessment
IRO-007	Monitoring the Reliability Coordinator Wide Area
IRO-009	Reliability Coordinator Actions to Operate Within IROLs
IRO-010	Reliability Coordinator Data Specification and Collection
ORG-004	Transmission Operator Certification – Data Acquisition and Monitoring
PER-003	Operating Personnel Credentials
PRC-001	System Protection Coordination

Related SARs

SAR ID	Explanation
Reliability Coordination: Project 2006-06	There are parallels between this SAR for Transmission Operators and the SAR for Reliability Coordinators that must be taken into account in the development of the eventual standards.

Regional Variances

Region	**Explanation**
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A

Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Electric System, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the Bulk Electric System. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. ('Violation severity levels' replaces the existing 'levels of non-compliance.') The violation severity levels must be applied for each requirement and may be combined to cover multiple requirements, as long as it is clear which requirements are included and that all requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: more than 95% but less than 100% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: more than 85% but less than or equal to 95% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: more than 70% but less than or equal to 85% compliant.

- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: 70% or less compliant.

Compliance Monitor
Replace, 'Regional Reliability Organization' with 'Regional Entity'

Fill-in-the-blank Requirements
Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization
Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates
Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan. The effective date should be linked to the NERC BOT adoption date.

Associated Documents
If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Functional Model Version 3
Review the requirements against the latest descriptions of the responsibilities and tasks assigned to functional entities as provided in pages 13 through 53 of the draft Functional Model Version 3.

Appendix B: List of Comments

The following items are comments received from various sources that shall be considered by the SDT.

COM-001-1

CESDT: (Compliance Elements Standards Drafting Team)

- R1: clarify 'adequate', 'reliable' and 'internally'.
- The statement 'Where applicable, these facilities shall be redundant and diversely routed' should be a guide and not a requirement. It would also appear that this is duplicated in COM-002-2, R1.
- R2: clarify the term 'Special attention'.
- R3: clarify 'shall provide a means' and the 'ability to investigate'.

VRFSDT: (Violation Risk Factors Standards Drafting Team)

- R6: administrative.

Version 0 Industry Comments:

- Gerald Reahlt, Manitoba: There may be redundancy here with Policy 5A Requirement 1.
- Robert Snow: R1 **-** In section R1, for all but the smallest areas, redundancy and diversely routed telecommunications is required.
- Guy Zito, NPCC: R1 thru R5 **-** Add "Transmission Owners, Generator Owners, Generator Operators and Load Serving Entities" to the list of FM entities this applies to.
- Ralph Rufrano, NYPA: NPCC's participating members recommend changing R1 to;
  Each Reliability Authority, Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator and Load Serving Entity shall provide adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability. Where applicable, these facilities shall be redundant and diversely routed. -and changing R2 – R5 from "Each Reliability Authority, Transmission Operator, and Balancing Authority shall" To "Each Reliability Authority, Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator and Load Serving Entity shall" -Remove R6 and attachment 029-1 should be removed. Those procedures apply to NERCnet users, which is a small subset of community that R1 – R5 apply to. Also, these procedures are the steps for obtaining and using NERCnet. Those procedures should not be part of a Reliability Standard.

FERC Order 693:

- Expand the applicability of the standard to include Generator Operators and Distribution Providers and include requirements for their telecommunication facilities (or as an alternative to applying this Reliability Standard to Generator Operators and Distribution Providers, develop a new Reliability Standard that will address the requirements for telecommunication facilities applicable to Generator Operators and Distribution Providers).
- Identify specific requirements for telecommunications facilities for use in normal and emergency conditions that reflect the roles of the applicable entities and their impact on Reliable Operation
- Include adequate flexibility for compliance with the Reliability Standard, adoption of new technologies and cost-effective solutions

COM-002-2

CESDT:

- R1, part 2: clarify ‘Such communication shall be staffed and available for addressing a real-time emergency condition’.
- R2: clarify ‘clear, concise and definitive manner’. Define ‘directive’.

V0 Industry Comments:

- Mike Kormos, PJM: In a Market environment voice communication with generators is not necessarily required.
- FRCC: R1 - Reliability Authority should be included in this requirement.
- Ray Morella, First Energy: R2 - All groups active in the industry should be required to report sabotage incidents and security breaches.
- Guy Zito, NPCC: R4 - Even though this is a direct translation of the existing Policy, NPCC requests a clarification of the repeat back requirements, specifically are they for emergency, abnormal, normal, all of the above, provide specific examples.

FERC Order 693:

- Expand the applicability to include distribution providers as applicable entities.
- Include a new requirement for the Reliability Coordinator to assess and approve actions that have impacts beyond the area view of a Transmission Operator or Balancing Authority.
- Require tightened communications protocols, especially for communications during alerts and emergencies.
  - Alternatively, develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26 in the manner described above.
- Include APPA’s suggestions to complete the Measures and Levels of Non-Compliance.

PER-001-0

V0 Industry Comments:

- Southern Company: Compliance Monitoring Process - The Data Retention requirement for this standard should be 1 year. The probability exists that over time, the job description and perhaps other documentation will be modified. There should not be a requirement to keep past versions of authorizing documents for an indefinite period of time.
- Bill Squib, ECAR: In the Compliance Monitoring Process… if the Reset Period is One Calendar Year, then why is the Data Retention Permanent. In addition, what kind of data is considered for Data Retention? Surely a 10-year old Job Description that has been updated several times does not need to be retained permanently.

TOP-001-1

CESDT:

- R8: essentially duplicated in other areas; clarify reactive power balance.

V0 Industry Comments:

- Michael Moltane, ECAR: (1) Need good, clear definition of “Reliability Emergency” for this to work. Otherwise we will get into the endless and age-old discussion of “what is an emergency?” (2) R1: Recommend adding wording to the sentence “clear decision making authority” that such authority should be documented and incorporated into Operating Procedures so that there will not be any confusion in real time emergencies as to who is responsible for what, and to whom.
- Roman Carter, Southern Company: (1) This req. states "The RA, BA, and TO shall have the responsibility…” The original language in Policy 5 for this requirement uses Operating Authority and this includes entities such as the GO, TO, and BA but not the Reliability Coordinator. Throughout this V-0 Standard the RA is substituted for the RC even within this requirement. Since the original policy says RCs are excluded, this poses a conflict for this requirement. This is also in Requirements 2, 4, and 5. (2) There are times when a Generator Operator must act quickly and may not have time to notify the Transmission Operator. There needs to be an exception here (like that listed in 7C for the RA and TOP) for emergency situations that allows follow up notification by the GO.
- Southern Company: R4 and R6 - Should specify that the local RA will handle all communications with other potentially impacted Reliability Coordinators. As written (Reliability Authority or …), these requirements could lead to multiple notifications and potential confusion as to exactly what action is going to happen or has taken place. In general, all communications with adjacent Reliability Authorities should be through the local Reliability Coordinator. (Note that R4 may intend that RA contact other RAs, etc., but this is not clear and could easily be misinterpreted.)
- Peter Henderson, IMO: In the sentence: “Under these circumstances the Transmission Operator or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive …” The use of “or” is confusing and may create ambiguity. The specific role of entity responsible for ‘providing’ and ‘receiving’ information needs to be clarified. Should this be combined responsibility applicable to all or for any? **For the purposes of effective implementation/enforcement of these standards, we recommended that the associated measures, compliance monitoring process and levels of non compliance should also be (a) simultaneously mapped/specified where these exist already and (b) specified/addressed in the very near future, where these do not exist today for consistency. **This comment also applies to Standards 19, 21, 26, 34 and 35.

FERC Order 693:

- Include Measures and Levels of Non-Compliance for Requirement R8.
- Consider adding other Measures and Levels of Non-Compliance in the Reliability Standard.
- Consider revising Requirements R7.2 and R7.3 to provide that the transmission operator may notify the Reliability Coordinator or the Balancing Authority that it is removing facilities from service as suggested by Santa Clara.

TOP-002-2

CESDT:

- R1, part2: clarify ‘Transmission Operator shall be responsible for using available personnel and system equipment’.
- R2: too vague
- R3: too vague; clarify ‘coordinate’.
- R4: too vague; clarify ‘coordinate’.
- R12: duplicated in FAC-013.
- R13: duplicated in MOD-024 & MOD-025.

- R17: incorrectly written.
- R19: too vague; clarify 'accuracy'; determine timeliness of model.

Regional Reliability Standards Working Group (RRSWG):

- R6: remove 'in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements'.
- R12: remove 'in accordance with filed tariffs and/or regional Total transfer Capability and Available Transfer capability calculation processes'.

V0 Industry Comments:

- Alan Johnson, Mirant: Concerned that the translation from Control Area to BA or TOP creates a new requirement for the GOP. The proposed language allows the possibility of the GOP having to perform tests at the request of both the BA and TOP. The GOP should only be required to perform 2 seasonal capability tests per year (winter and summer) within pre-defined parameters.
- Southern Company: General - Hierarchical structure seems to be implied, but not explicitly defined in the translation of Control Area and Reliability Coordinator language to functional model language. May want to consider writing requirements such that all Balancing Authorities and Transmission Operators within a given Reliability Authority's area should coordinate their operations planning, etc.
- PG&E: R3, R4, R5 — The parentheticals "where confidentiality agreements allow" imply that confidentiality agreements trump coordination of operational plans needed to assure system reliability. They should be eliminated. Reliability Authorities would then be responsible for coordination between each other, etc. Seems confusing and/or difficult to follow as written.
- Roman Carter, Southern Company: (1) 4, 5 - Requirement says LSE, TSP, and GO coordinate with BA (where confidentiality agreements allow). Under the F.M., the BA can delegate certain tasks that prevent the BA from meeting the Conf. Agreement in order for the BA to meet the obligations of the BA. Version-0 Standard should recognize this ability. (2) Requirement states without intentional delay. How is this enforceable? The burden of proof is with the enforcement organization.
- Ray Morella, First Energy: R7 - Need to explicitly and precisely define what N-1 contingency means.
- Raj Rana, AEP: R18 - R18 only needs to state that the BALANCING AUTHORITIES shall, without any intentional time delay, communicate the information described in the requirement R15 above to their RELIABILITY AUTHORITY, or add such statement to R15. R17 already requires notification to the RA, and these were the activities that Policy today requires notification to the RA, as referenced in Policy 6A R6.1 - 6.5.
- Peter Lebro, National Grid: R3, R4, R5, R12, R17: Confidentiality of information should not be a factor when it comes to reliability – this needs to be addressed otherwise Companies may hide behind the confidentiality clause and not provide the data necessary to conduct operational reliability assessments and coordinate reliable operations.

FERC Order 693:

- Delete references to confidentiality agreements in Requirements R3 and R4, but address the issue separately to ensure that necessary protections are in place related to confidential information.
- Require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.
- Require next day analysis of minimum voltages at nuclear power plants auxiliary power busses.
- Require simulation contingencies to match what will actually happen in the field.

TOP-003-0

VRF:

- R4: poorly written.

V0:

- Peter Lebro, National Grid: Standard 16:R1, Standard 37:R4: In the standards it states outage data (generation and transmission) is only required to be submitted by noon of the day ahead, the emphasis should be on submitting the data as soon as it is known but no later that noon day ahead.
- Anita Lee, AESO: CMP - Third paragraph - The RA should "direct" the cancellation of an outage, not "request".
- Robert Snow: Outage information is needed by neighboring reliability authorities much sooner than one day prior to the outage.

FERC Order 693:

- Include a new requirement to communicate longer term outages well in advance to ensure reliability and accuracy of ATC calculations.
- Make any facility below the voltage thresholds that, in the opinion of the Transmission Operator, Balancing Authority, or Reliability Coordinator, will have a direct impact on the operation of the Bulk Power System, subject to Requirement R1 for planned outage coordination.
- Incorporate an appropriate lead time for planned outages.

TOP-004-1

CESDT:

- R1: TOP cannot always operate within IROL.
- R2: need to be able to measure ‘planning to prevent such an occurrence’.
- R3: same comments as R2; clarify ‘when practical’.
- R5: clarify ‘every effort to remain connected’ and ‘imminent danger’.

V0:

- Brandian, ISO-NE: In the existing policy the overall role of monitoring of SOL or IROL was assigned to a Control Area. In the applicable version 0 standards a clarification on the role and relationship between Reliability Authority and Transmission Operator should be made with regards to the monitoring of SOL & IROL.
- Guy Zito, NPCC: (1) These Standards must clearly identify, define and provide examples of what a SOL and IROL are. The reason for this is that this is not consistently interpreted by industry. (2) (Also in R5) This needs to be clarified whether these requirements have to be fulfilled by both presently worded RA (i.e. new proposed terminology RC) and TO - “individually or jointly”. It is not clear that who would be overall monitor. A more clear role needs to be identified in this standard. Also Reliability entity should be termed as ‘RC’.
- Robert Snow: Transmission Security during operation should conform to the applicable portions of Table 1 in the planning standards.

- Vinod Kotecha, Con Edison: There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. The RC has been designated as being responsible for maintaining the interconnection within IROLs, however debate on how these should be calculated continues.
- Tracy Edwards, BPA: R5 indicates that every effort shall be made to remain connected to the Interconnection. However the second sentence of the requirement implies that it may be acceptable to disconnect from the Interconnection if there is imminent danger of violating an IROL or SOL. There can be other conditions other than violating IROL's or SOL's that place the system at great risk. In fact, violating an IROL or SOL in itself does not necessary mean the system is at imminent risk. Therefore, change the second sentence of R5 to read as follows: The Reliability Authority or Transmission Operator may take such actions as disconnecting from the Interconnection, as it deems necessary, to protect its Area.
- Roman Carter, Southern Company: It is not practical to say the RA and the TOP operate, when practical, to protect against instability, separation, or cascading outages. Recommend removing "when practical" because when is it ever practical to allow cascading outages.

FERC Order 693:

- Modify Requirement R4 to state that the system should be restored to respect proven limits as soon as possible, taking no more than 30 minutes.
- Define high risk conditions under which the system must be operated to respect multiple outages in Requirement R3.

TOP-005-1

V0:

- Brandian, ISO-NE: Applicability - Add Generator Owners and Load Serving Entities. Extend R5 to include these Functional Model entities.
- Ed Riley, CAISO: R1 - Current policy is for data to be updated every 10 minutes, and is in Standard 15. This rate is too slow and should be increased (every 4-10 seconds) when possible. This should be addressed in Version 1.
- Robert Snow: In Attachment 1, the generator data should include status of voltage control and power system stabilizer facilities.
- Tracy Edwards, BPA: Attachment 015-1: Need a time frame for this data, it is not measurable as it reads now.
- Peter Lebro, National Grid: National Grid USA would like to make the following recommendations to be considered when drafting the next draft of Version 0. Standard 15: There should be a requirement on generators to provide the necessary data as there is a requirement on the PSE's (R6), a paragraph R7 should be inserted which reads 'Generation Operators shall provide information requested by their host Balancing Authority and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.'

FERC Order 693:

- Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.
- Delete references to confidentiality agreements, but address the issue separately to ensure that necessary protections are in place related to confidential information.

TOP-006-1

CESDT:

- R3: quantify relay information that is required and the scope of the relays to be included; clarify what constitutes 'appropriate technical information'.
- R6: clarify 'measure requirement'

VRF:

- R1, 1.1 & 1.2: may need 'available in emergency situation'
- R3: define 'appropriate'.
- R4: what information is required and what is a load pattern?

V0:

- Guy Zito, NPCC: Associated Measure, Compliance Monitoring Process and Levels of Non Compliance are missing and needs to be defined in this standard simultaneously.
- Michael Moltane, ECAR: R1.1: Should clarify that the Gen Operator needs to provide "normal and emergency capability for use", as opposed to current wording of just ".all generation resources available for use" (i.e., stretch capability, maximum run time for emergency capability, etc.). R7: Indicates that entities shall "monitor system frequency"……recommend adding wording to indicate frequency shall monitor system frequency at multiple points on their system.
- Alan Boesch, NPPD: R4 - In the Functional Model load forecasts are developed by the Load Serving Entity and provided to the Balancing Authority. The BA sends the aggregated information to the RA. The TOP is not involved in this process. Please change the requirement to match the functional model.
- Various entities: R4 - Load forecasting is the starting point for planning capacity for obligations and thus, deemed to be required for reliability.

FERC Order 693:

- Include a new requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk Power System.
- Clarify the meaning of "appropriate technical information" concerning protective relays.

TOP-007-0

V0:

- Ed Riley, CAISO: Measures - 2nd paragraph should be changed to read "…within IROL or SOL…" The CAISO believes that suggesting that the determination of an SOL becoming an IROL after the fact is inappropriate.
- Eric Grant, Progress: R1-R5 - In general, unless better bounds/criteria are set for the determination of IROLs, this standard will not be enforceable or auditable.
- Phil Creech, Progress: "Applicability" for this standard should include "Reliability Authorities".
- Various entities: R5 - This should be considered as a compliance monitoring or administrative procedure rather than a standard.

- Martin Huang, BC Transmission: R1 and M1 both requires the Reliability Coordinate be informed of any IROL or SOL violation but the level of non-compliance only applies when the limit is exceeded more than 30 minutes and none for failure to report the violation.
- Tracy Edwards, BPA: (1) Compliance Monitoring Process: (bullets following the first paragraph) 2) … Is vague and not measurable 3) … Would not necessarily make it an IROL. 4) … Would not necessarily make it an IROL. 5) … Is vague and there is no unacceptable loss of load definition for NERC that is measurable. (2) Compliance Monitoring Process: (first paragraph, second sentence) If this sentence were true the violation would have been an IROL to begin with. Give an example of this scenario. (3) Give an example of how you would show evidence something was evaluated. This does not seem like a possible measure. Also the RC may not have needed to give any additional direction and would therefore not have any evidence as required by the measure.
- Linda Campbell, FRCC: Standard 008, M1-M3. What kind of evidence is anticipated? The word evidence can be very subjective and broad. Also the RA should be removed from these measures.

FERC Order 693:

- Consider comments from APPA, FirstEnergy and SoCal Edison that the Reliability Standards would benefit from the elimination of overlapping matters in TOP-007-0 and TOP-008-1.
- Consider comments from the NRC that raised some significant issues regarding nuclear power plants voltage requirements.

TOP-008-0

CESDT:

- R2: clarify ‘prevent the likelihood’.
- R4, part 2: clarify ‘in all operating timeframes’.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Maureen E. Long
Standards Process Manager

May 15, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Periods Open

The Standards Committee (SC) announces the following standards action:

SAR for Real-time Operations (Project 2007-03)
Posted for 30-day Comment Period May 15–June 13, 2007

The SAR for Project 2007-03 Real-time Transmission Operations and Balancing of Load and Generation proposes modifying the following standards that relate to various aspects of Reliability Coordination:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The modifications will address concerns raised by FERC and stakeholders and will bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines. Please use the comment form to provide comments on the first draft of this SAR.

SAR for Reliability-based Control (Project 2007-18)
Posted for 30-day Comment Period May 15–June 13, 2007

The SAR for Project 2007-18 Reliability-based Control proposes developing requirements to achieve the following objectives:

- To maintain Interconnection frequency within predefined frequency limits under all conditions (i.e., normal and abnormal), to prevent frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or Cascading outages that adversely impact the reliability of the Interconnection. (Work brought into this SAR is from BAL-007 though BAL-011.)

- To support elimination of SOL/IROL violations caused by excessive (as determined by this standard) Area Control Error ("ACE"). (Could be a separate and individually-balloted Standard)
- To prevent Interconnection frequency excursions of short-duration attributed to the ramping of on and off-peak Interchange Transactions. (Could be a separate and individually-balloted Standard)
- To support timely transmission congestion relief by requiring corrective load/generation management within a defined timeframe when ACE is impacted by the curtailment of Interchange Transactions under transmission loading relief procedures. (Could be a separate and individually-balloted Standard)
- To address relevant directives in FERC Order 693.

Please use the comment form to provide comments on the first draft of this SAR.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments:

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☐ No

   Comments:

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☐ Yes

   ☐ No

   Comments:

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR:

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

   ☐ Yes

   ☐ No

   Comments:

7. **Do you agree with the scope of this SAR?**

   ☐ Yes

   ☐ No

   Comments:

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

   ☐ Regional Variances

   ☐ Business Practices

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9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☒	1 — Transmission Owners
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3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

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1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments:

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: We disagree with this statement. Just what does the SAR DT consider to be a true BES reliability issue? The team's opinion seems contradictory to NERC's efforts to have the Regions agree that all non-radial transmission facilities 100 kV and above are Bulk Electric System facilities. On one end of the spectrum there is a NERC effort to expand the definition and size of BES. Then you efforts like this SAR to reduce the size and scope.

   While the most severe and significant BES reliability issue may be IROL violations (IROL violations can lead to instability, uncontrolled separation, or cascading outages), that surely is not the only reliability issue. Multiple SOL events can lead to a situation where you have a new, non-studied IROL. Should we not operate the system such to prevent us from entering or approaching IROL limits? If the only limits that have applicable Reliability Standards is IROLs, then are we not setting up the system to approach the "edge of the cliff" before we take appropriate defensive action? While we agree not all SOLs have a significant impact on the overall reliability of the BES, we do not agree that means all requirements related to SOLs should be removed from the NERC Standards. That would be a move towards less reliability in the future, not a step towards improving reliability.

   And just what is meant by local utility operations not being a true BES reliability issue. If the system is not operated to respect SOLs, then that could jeopardize a firm power purchase from a distance resource via firm transmission service that a "local utility" is relying upon. Loss of that firm power purchase, could lead to having to shed customer load? Why is that not a BES reliability issue? Isn't that one of the reasons the BES exists is to support such commerce? Violating SOLs could also result in the tripping of generation outlets, resulting in loss of generation. That too is not a BES reliability issue? Before we could support removing requirements related to SOLs, the SAR DT team would need to provide a definition of what exactly is considered a BES reliability issue.

Most of the TLRs that are implemented today are for relieving SOLs not IROLs. Therefore, removing requirements related to SOLs would be in direct conflict with current practices and does not improve the reliability practices from what we have today. At a minimum, RCs and TOPs need to monitor and know the EHV system SOLs and ensure operation within those SOLs and to monitor and operate to other SOLs as specified in the agreements between the RC and TOPs and BAs (see ORG-021-1 R3).

While it is not practical or necessary to ticket every car speeding on the freeway, on the contrary it is also not practical or necessary to remove the speedometer from the cars. We feel that the requirements for the SOL are like the speedometers; therefore, removing requirements related to SOLs is inappropriate and could lead to less reliable operations.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

☒ Yes

☐ No

Comments: Yes, we agree that the Standard Drafting Team should review and consider the merits of those comments and incorporate those comments that make sense and our complimentary to maintaining and improving reliable operations into the revised Standards.

4. **Are there any standards included in the SAR that shouldn't be included?**

The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

The following standards should be added to the SAR:

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments:

7. Do you agree with the scope of this SAR?

☒ Yes

☐ No

Comments: We agree with the purpose stated for this SAR. We do not agree with all of the specific changes suggested in the SAR. However, the SAR is written that the Standard Drafting Team is to consider the changes, which we do support. We believe that through a thorough debate and analysis by the Standard Drafting Team, that they too will conclude that not all the recommendations should be implemented.

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments: AEP encourages additional aids (i.e. whitepapers and/or teleconferences) during the drafting process to better understand the drive for removing SOLs from some of the standards.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
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Organization: Ameren		
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E-mail: jhackman@ameren.com		
NERC Region		**Registered Ballot Body Segment**
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2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☒ Yes

   ☐ No

   Comments:

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments:

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   The following standards should be added to the SAR:

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

   ☒ Yes

   ☐ No

   Comments: It is important that the standards address those things, and only those things, that affect the reliability of the BES so that time and attention are not diverted from the most worthwhile initiatives.

7. **Do you agree with the scope of this SAR?**

   ☒ Yes

   ☐ No

   Comments:

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

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<table>
<tr><th colspan="3">Individual Commenter Information
(Complete this page for comments from one organization or individual.)</th></tr>
<tr><td colspan="3">Name: Jason Shaver</td></tr>
<tr><td colspan="3">Organization: American Transmission Co.</td></tr>
<tr><td colspan="3">Telephone: 262 506 6885</td></tr>
<tr><td colspan="3">E-mail: jshaver@atcllc.com</td></tr>
<tr><td>NERC Region</td><td></td><td>Registered Ballot Body Segment</td></tr>
<tr><td rowspan="10">☐ ERCOT
☐ FRCC
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</table>

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Lead Contact:

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Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☒ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments: Standards define "good utility practices" therefore it's our opinion that these requirements should remain.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: ATC does not agree with SAR DT that SOLs are only important to local operations and that they should be removed from these standards. If SOLs are removed from NERC standards then any real-time identifications of an SOL that becomes an IROL will be difficult if not impossible to determine.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☐ Yes

   ☒ No

   Comments: Comments submitted during the comment period should be given a greater weight in the creation of new standards. Comments submitted to other groups and different efforts are specific to those initiatives and the inclusion in this effort should be limited.

4. **Are there any standards included in the SAR that shouldn't be included?**

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The following standards should be added to the SAR:

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☒ No

Comments: ATC agrees that there is a reliability-related need to review and revise this set of standards, but we do not agree with the overly prescriptive changes appearing in the SAR.

7. Do you agree with the scope of this SAR?

☐ Yes

☒ No

Comments: The scope of this SAR is overly prescriptive in that is has already determined a solution to the perceived deficiency. A scope needs to be detailed enough to provide a solid base for discussion and review, but not so detailed that the solution has been identified. The solution will be developed by the SDT along with industry feedback. ATC believes that this SAR is overly prescriptive and should be re-written.

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments: Comment in the SAR:

"R14 and R15 apply to the Generator Operator and as such do not belong in the TOP standards. The drafting team should look to find another place for these requirements if possible."

ATC disagree with this statement. The "Purpose" statement sets the need for the standard. All entities that are needed to support the "Purpose" should be identified in the Applicability section. The label of TOP should not be the justification to exclude any entity that is not a Transmission Operator.

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Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	Anthony Alford	
Organization:	CenterPoint Energy	
Telephone:	713-207-2265	
E-mail:	anthony.alford@centerpointenergy.com	
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1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments:

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☐ No

   Comments:

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☐ Yes

   ☒ No

   Comments: CenterPoint Energy disagrees with the suggestion to remove the real and reactive capability verification testing from TOP-002-2, R13. The capability of a generator must be periodically tested to ensure that the machine will perform to its limits. Additional language should be added such that these tests are conducted on a periodic basis and not just at the requests of a BA or TOP.

   CenterPoint Energy believes that the requirements of TOP-002-2, R14 and R15 do belong in the Transmission Operations Standards as those variables will have a direct impact on daily operations. Any additional details or clarification can be added to other standards if necessary.

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR:

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

   ☐ Yes

   ☐ No

   Comments:

7. **Do you agree with the scope of this SAR?**

   ☐ Yes

   ☐ No

   Comments:

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

   ☐ Regional Variances

   ☐ Business Practices

   Comments:

9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

   Comments:

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information		
(Complete this page for comments from one organization or individual.)		
Name:	Greg Rowland	
Organization:	Duke Energy	
Telephone:	704-382-5348	
E-mail:	gdrowlan@duke-energy.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☒ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments: Where the identification of procedures and good utility practice bring clarity to TOP requirements, they should be retained, although not as separate requirements.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: Where SOLs impact the Bulk Electric System, they are a reliability issue and should not be moved into guides or other reference documents.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☒ No

   Comments: Comments submitted should certainly be considered by the standard drafting team, but the standard drafting team should not be bound to incorporate all comments into the revised standards.

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed: COM-001-1, COM-002-2 and PER-001-0. See response to question 7.

5. **Are there standards that should be added to the SAR?**

The following standards should be added to the SAR: None

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments: The reliability-related need is to provide clarity and remove redundancy.

7. Do you agree with the scope of this SAR?

☐ Yes

☒ No

Comments: This SAR should focus only on TOP standards.

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments: None

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments: If the ultimate goal is to eliminate PER-001-0 as stated on page SAR-4, it should be noted that responsibility and authority are to be provided to "operating personnel" in either a TO or a BA. However, in standard TOP-001 Requirement 1, it deals specifically with Transmission Operators, and Balancing Authority personnel are not covered under this standard. Consideration should be given to either add BAs to TOP-001 R1 or they should be given "responsibility and authority" in some other standard if PER-001 is eliminated.

Also, NERC should create a companion database for the standards that links each requirement, its compliance elements and applicable entities. Such a cross-reference would facilitate standards actions dealing with groups of standards.

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information

(Complete this page for comments from one organization or individual.)

Name:	Ed Davis
Organization:	Entergy Services
Telephone:	504-576-3029
E-mail:	edavis@entergy.com

NERC Region		Registered Ballot Body Segment
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☒ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments:

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☒ Yes

   ☐ No

   Comments:

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

   No.

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR: No.

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments:

7. Do you agree with the scope of this SAR?

☒ Yes

☐ No

Comments:

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments:

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Will Franklin	
Organization:	Entergy Services, Inc (Generation/System Planning & Operations)	
Telephone:	281-297-394	
E-mail:	wfrankl@entergy.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☒ **SERC**	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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- COM-002-2 Communications and Coordination
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- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
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- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words “**Real-time TOP & BA**” in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments: Move to reference documents or eliminate 'good practices' from standards, and also eliminate redundant requirements.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☐ No

   Comments:

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR:

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments:

7. Do you agree with the scope of this SAR?

☒ Yes

☐ No

Comments:

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments:

We agree that the proposed changes need to be evaluated. However, it is important that the revised standards are balloted separately so that the entire set is not rejected because of an issue with one of the standards nor approved as a set with flaws or concerns in one or more of the standards.

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: H. Steven (Steve) Myers		
Organization: ERCOT		
Telephone: 512-248-3077		
E-mail: smyers@ercot.com		
NERC Region		**Registered Ballot Body Segment**
☒ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments: Such information is of value and should not be lost, but does not belong in a Standard. A Standard must apply continent-wide and not be of the nature of dictating any particular practice or procedure.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☒ Yes

   ☐ No

   Comments: There may be some confusion across the industry about "what are SOLs". I think there is good agreement that IROLs are applicable at the NERC Standard level, but there is some identifiable reluctance within the industry to say that there is no place at all for SOLs in the NERC Standards. At the very least, there needs to be a good definition of SOL (which I believe there is), but some are concerned with the idea that IROLs are a "subset" of SOLs. Some believe that once a differentiation is made, the two should be considered separately and have separate requirements. I personally believe that IROLs are a subset of SOLs. I further believe that routine planning, operations planning, and real-time operations should be addressing all SOLs. Only during real-time operations or, more accurately, fresh post-analysis, can it be fully determined that an SOL may have sufficient consequences associated with it to qualify it as an IROL. If an IROL can be identified in advance, since by definition it relates to a single contingency, I believe a case could be made that planning and operations planning requirements have not been satisfied. In the great majority of cases, a system may be driven into an IROL through a series of unplanned events such that the system indeed may be subject to undesirable results from a "next" single contingency. However, prudent operations should dictate that no system plan to be in such a state.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

☒ Yes

☐ No

Comments: Each submitted comment containing technical content deserves to be given equal review by the Standard Drafting Team (SDT) once a SAR has been approved and a SDT has been selected.

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR:

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☒ No

Comments: I believe that revising the set of standards for clarity and for reducing redundancy will benefit reliability by reducing confusion. There is also a common sense reason to revise them to avoid "multiple jeopardy" by exposure to the same requirement in multiple standards.

7. Do you agree with the scope of this SAR?

☒ Yes

☐ No

Comments:

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven’t identified above, please provide them here.

Comments:

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Doug Hohlbaugh	
Organization:	FirstEnergy	
Telephone:	330-384-4698	
E-mail:	hohlbaughdg@firstenergycorp.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
John Reed	FE		
Dave Folk	FE		

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☒ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments: FirstEnergy agrees in general that Good Utility Practices in and of themselves do not belong in the standards. However, for the two examples cited we believe these are important processes for ensuring a reliable electric system and therefore should remain within the reliability standards. Exclusion of requirments based on Good Utility Pratices will need to be evaluated and addressed on a case by case basis and commented on via the standard drafting process.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☒ Yes

   ☐ No

   Comments: The reliability standards governing real-time operations should be focused on the subset of SOLs that qualify as IROLs.(reference FAC-010-1 R1.3). Blanket removal of all SOL references should be avoided and will need to be done on a case by case basis.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR:

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments:

7. Do you agree with the scope of this SAR?

☒ Yes

☐ No

Comments:

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments:

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: FRCC

Lead Contact: Eric Senkowicz

Contact Organization: FRCC

Contact Segment: 10

Contact Telephone: 813-207-7980

Contact E-mail: esenkowicz@frcc.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Steve Wallace	Seminole Electric Cooperative	FRCC	4
Ed DeVarona	Florida Power and Light	FRCC	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments: Subjective commentary that is not measurable or enforceable should be removed from the standards and placed in the Reliability Readiness Evaluation and Improvement Program Reference Manual or something similar.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: SOLs are a critical part operational situational awareness and of a "defense-in-depth" approach to operating reliably. It is critical for the Transmission Operator and Reliability Coordinator to be aware of areas that are stressed within his/her TOP and RC area (local and wide area view). Advance knowledge of what may initially be local or even minor issues to the BES, will allow the development of the most effective and appropriate solutions for resolving the SOLs and ensuring that they DO NOT evolve into IROLs.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments: Not sure what the question is but, Yes capturing previous analysis regarding standard content and including in this SAR and subsequent standard revisions is appropriate and effective use of previous NERC groups efforts.

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR:

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

   ☒ Yes

   ☐ No

   Comments:

7. **Do you agree with the scope of this SAR?**

   ☒ Yes

   ☐ No

   Comments:

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

   ☐ Regional Variances

   ☐ Business Practices

   Comments:

9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

Comments: The revisions being made under this SAR should be well coordinated with the revisions being made under the Reliability Coordination SAR (Project 2006-06). Both SARs are seeking to revise COM-001 and COM-002. It is also critical that language proposed in the revisions of both projects be well coordinated because of the interrelated nature of the applicable standards.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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E-mail: champagne.roger.2@hydro.qc.ca		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments: We agree that good utility practice and procedures should not be included in standards. However, care should be taken not to remove coordination requirements which are in fact necessary to reliability planning and operation.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: We strongly disagree with this idea. Respecting SOLs is a fundamental operational requirement. Transmission Operators must be required to closely montior their area; failing to do so may ultimately lead to cascading failures, as was witnessed on August 14, 2003. An SOLs, left unchecked, will become an IROL, which is why it is imperative that all SOLs be monitored and respected at the TOP level.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments: This may be a reasonable approach. However, the SAR DT may want to consider if they then need to pass all comments dealing specifically with the standards on to the Standards Drafting team from this process.

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

Some of the standards included in this SAR for revision appear to create a conflict with other ongoing SAR and Standard drafting activites. We are becoming more and more concerned about the parallel changes taking place.

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR: No.

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

   ☒ Yes

   ☐ No

   Comments:

7. **Do you agree with the scope of this SAR?**

   ☐ Yes

   ☒ No

   Comments: Please see response to Q#4.

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

   ☐ Regional Variances

   ☐ Business Practices

   Comments:

9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

   Comments:

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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Organization: IESO		
Telephone: 905-855-6187		
E-mail: ron.falsetti@ieso.ca		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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- TOP-002-2 Normal Operations Planning
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- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments: We concur that good utility practices and administrative procedures should not be included in standards. Nonetheless, we suggest the SDT to assess which of the existing requirements, including the procedural ones, are indeed actions needed to preserve reliability and hence keep them in the standards.

   While we agree that TOP-002-2, R2 may be removed, we do not agree that TOP-001-1 R7 should be removed since the notification and coordination of generation and transmission outages are necessary to ensure that reliability impact of the planned removal of the BES facility is assessed. It is not an administrative procedure or good utility practice; it is a reliability requirement.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: We strongly disagree with this notion. Respecting SOLs and mitigating their violations are fundamental to the reliable operation of the transmission operator's area which may ultimately affect the interconnected system. And since IROLs are a subset of SOLs, and that some SOLs may become IROLs as system condition changes, it is imperative that all SOLs be monitored and observed at all time.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments: This seems to be a reasonable approach. However, the SDT should take these into consideration only when reviewing and revising the standards, and use its judgment on their individual merit rather than taking them as given mandates or directives.

4. **Are there any standards included in the SAR that shouldn't be included?**

The following standards were included in the SAR and should be removed:

(i) We do not understand the basis to include COM-001-1, COM-002-1 and EOP-001-0 in this SAR. While there are requirements in these standards that reference TOPs, there are other standards that also reference TOPs but they are not included in this set.

(ii) Some of the standards included in this SAR for revision appear to create a coordination need or potential conflicts with other SARs and draft standards:

(a) The Operating Personnel Communications Protocol (OPCP) SAR is proposing to modify COM-001-1, COM-002-1, TOP-001-1, TOP-002-2, TOP-007-0 and TOP-008-1. How does this SAR Drafting Team propose to coordinate with the OPCP SAR drafting team to avoid either duplicated work effort or making changes to these standards while the draft set proposed by the other SDT are being commented or balloted? It seems like this would be difficult to accomplish and that one SAR should be delayed.

(b) The Operate within Interconnected Operating Limits SDT is in the process of modifying the TOP-003, TOP-005, and TOP-006 standards as a result of changes to IRO-007-1 to IRO-011-1 standards. The coordination issues as indicated above would also need to be considered. We suggest that drafting of the standards included in this SAR be put on hold until after the IRO standards are balloted and approved.

(c) The Reliability-based Control SAR, which will develop the BAL-007 to BAL-011, standards is posted for comments. The coordination issues as indicated above would also need to be considered. We suggest that drafting of the standards included in this SAR be put on hold until after the BAL standards are balloted and approved.

(d) Finally, the System Personnel Training drafting team is proposing to eliminate PER-001 through PER-004. This SAR would have to be updated to reflect those changes. Again this SAR should be put on hold until the PER standards are balloted.

5. **Are there standards that should be added to the SAR?**

The following standards should be added to the SAR: No.

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments:

7. Do you agree with the scope of this SAR?

☐ Yes

☒ No

Comments: Please see our comments under Q2 and Q4 regarding the notion of the SAR DT, and the potential conflicts with other efforts currently underway or to start soon.

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments:

Specific to the proposed changes to the standards, we offer the following comments:

TOP-001

R2: the SDT suggests to remove this requirement. However, R2 holds TOP responsible for taking immediate actions to alleviate operating emergencies which may be within the TOP area and not monitored by an RC, whereas R3 requires several operating entities to comply with the RC directives. The two requirements serve different purposes.

R8: the SDT suggests to delete this requirement. We suggest the SDT to exercise caution and compare this requirement (restoring the system during an emergency) with other related standards to ensure that this is indeed covered elsewhere.

TOP-002

R1: the SDT suggests to remove this as it is redundant with TOP-008-1 R1. Please note that TOP-002 R1 requires plans whereas TOP-008 R1 requires TOP to take action in real time. These reuqirements are different. If the SDT wants to revise TOP-002 R1 to eliminate vague requirements, we suggest that the second sentence "In addition, each Balancing Authority andTransmission Operator shall be responsible for using available personnel and systemequipment to implement these plans to ensure that interconnected system reliability will be maintained." be deleted.

R3: the SDT suggests deleting R3 as it is redundant with TOP-004-1 R1. We disagree with this proposal. R3 requires the various operating entities to coordinate and develop operational plans; whereas TOP-004-1 requires the TOP to operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs). They are required for different time frames and purposes.

R4: the SDT suggests deleting R4 as it is redundant with IRO-005-2, R9. We Disagree with this proposal. Deleting R4 would remove the obligation for BA and Top to coordinate their activities with the RC. Additionally, the two requirements serve different purposes: R4 in TOP-002 serves to ensure that normal Interconnection operation will proceed in an orderly and consistent manner; whereas R9 in IRO-005-2 serves to require the RC to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations.

R6: the SDT suggests deleting R6 as it is redundant with BAL-002-0 R4 and IRO-005-2 R9. We agree that there is redundancy with BAL-002-0 R4, but we not agree that it is redundant with IRO-005-2 R9. Deleting R6 would remove the obligation for BA and Top to coordinate their activities with the RC. Additionally, the two requirements serve different purposes: R6 in TOP-002 require TOP and BA to plan for contingencies; whereas R9 in IRO-005-2 serves to require the RC to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations.

R7 and R9: the SDT suggests deleting these requirements as they are redundant with BAL-007 through -011. We do not agree with the deletion of both requirements, due to the fact the standards BAL-007 to BAL-011 have failed the ballot process, and are now part of the Reliability-based Control SAR which is posted for comments. Please see our comments on Q4 (ii), above.

R8, R10 and R11: the SDT suggests deleting these requirements as they are redundant with IRO-005-2 R9. We agree with this deletion provided that R4 is retained. Othewise, R10 and R11 should be retained.

R18: the SDT suggests to move this to FAC-009-1. We do not agree since the purpose of FAC-009-1 is "To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or Methodologies". We veiw that R18 crosses a number of Standards so there may be a better home than FAC-009-1.

TOP-003-0

R3: the SDT suggests deleting R1.3 as it is redundant with IRO-010, R3 as part of the over-all data specification effort. We believe the referenced requirement should be R4.

TOP-004-0

R1: the SDT suggests deleting R1 as it is redundant with IRO-009-1, R4. We disagree with this. SAR IRO-009-1 holds the RC responsible for operated within IROL. We feel strongly that the TOP must also operate its system to respect IROL. Further, we need to defer any changes to remove or modify SOL until after the definition of Adequate Level of reliability is defined. We also provided other reasons for retaining it. Please see our comments on Q2, above.

R2: the SDT suggests deleting R2 as it is simply the definition of an IROL and is redundant with FAC-010-1 and FAC-011-1. We disagree with this proposal since R2 requires TOP to operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. FAC-010-1 and FAC-011-1 deal with the methodology to determine SOL and IROL. They hold different entities for doing very different things altogether.

R3: We disagree with removing this requirement for the above same reason.

TOP-005-1

R2: the SDT suggests deleting this requirment. We agree that R2 is not a reliability requirement, but the SDT needs to recommend a home for entities that receive data from the ISN that it must sign the NERC Confidentiality Agreement for “Electric System Reliability Data".

TOP-006-1

R1: the SDT suggests deleting R1 as it is redundant with FAC-009-1, R2. We disagree with this proposal since R1 deals with real-time data such as facility status, resource availability; whereas FAC-009-1 deals with establishing ratings.

R4: the SDT suggests deleting R4 as it is redundant with BAL-001 and -002 and is also addressed in IRO-010-1, R1 and R3. We disagree as R4 requires the operating entities to do things that are very different from any of BAL-001, BAL-002 and IRO-010-1.

R7: the SDT considers deleting Balancing Authority as it is covered in BAL-005-0, R8 and deleting Reliability Coordinator as it is covered in BAL-008-1, R1. We do not agree with both. In the first case, the requirements for the BA in R7 is to monitor system frequency which is different than those in BAL-005-0, R8 which specify the data and metering requirements. In the second case, BAL-008 doesn't yet exist (falied ballot).

TOP-008

R3: the SDT suggests deleting R3 as it is a local utility risk consideration and not a reliability issue as currently worded. We do not agree with the deletion since the requirement implies that the action taken by the TOP has interconnected system implication.

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Group Comments (Complete this page if comments are from a group.)

Group Name: IRC Standards Review Committee

Lead Contact: Charles Yeung

Contact Organization: SPP

Contact Segment: 2

Contact Telephone: 832-724-6142

Contact E-mail: cyeung@spp.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Jim Castle	NYISO	NPCC	2
Alicia Daugherty	PJM	RFC	2
Ron Falsetti	IESO	NPCC	2
Matt Goldberg	ISO-NE	NPCC	2
Brent Kingsford	CAISO	WECC	2
Steve Myers	ERCOT	ERCOT	2
Anita Lee	AESO	WECC	2
Bill Phillips	MISO	RFC+	2
		MRO+	
		SERC+	
		SPP	

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
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4. This satisfies the ANSI procedure requirement for five-year review of the standards.

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You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments: Good utility practices and procedures should not be included in standards. They are vague statements and do not belong in the standards even as a reference. If good utility practice statements were acceptable there would only be a need for one requirement and that is that all entities shall institute good utility practice. True standards need to be developed and superfluous information should not remain in the standards.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☐ No

   Comments:

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments: This may be a reasonable approach. However, the SAR DT may want to consider if they then need to pass all comments dealing specifically with the standards on to the Standards Drafting team from this process.

4. **Are there any standards included in the SAR that shouldn't be included?**

The following standards were included in the SAR and should be removed: We do agree that this SAR appears to cover the right set of standards. However, it potentially conflicts with other SARs and draft standards.

The Operating Personnel Communications Protocol (OPCP) SAR is proposing to modify COM-1-1, COM-002-2, TOP-001-1, TOP-002-2, TOP-007-0, TOP-008-0 standards. All of these standards are proposed to be modified in this SAR. How does this SAR Drafting Team propose to coordinate with the OPCP SAR drafting team. It seems like this would be difficult to accomplish and that one SAR should be delayed.

The Operate within Interconnected Operating Limits Standard Drafting team is in the process of modifying the TOP-003, TOP-005, and TOP-006 standards. Assuming these standards are eventually approved, this SAR will have to be modified to reflect the new versions of the standards. Again, this SAR should be delayed until the Operate within Interconnected Operating Limits Standards have completed the ballot process.

Finally, System Personnel Training drafting team is proposing to eliminate PER-001 through PER-004. This SAR would have to be updated to reflect those changes. Again this SAR should be delayed until these standards are balloted.

5. **Are there standards that should be added to the SAR?**

The following standards should be added to the SAR: No.

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments:

7. Do you agree with the scope of this SAR?

☒ Yes

☒ No

Comments: This SAR should be written to apply only to TOPs. This is an opportunity to create a good quality set of standards and eliminate the existing ambiguous requirements. You should start with a clean slate.

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments: The SAR proposes to add the language "without delay" to a number of requirements. We are concerned that this wording could be interpreted in a standard to require the need for immediate control action. We propose that the standard drafting team should clarify that the "without delay" language does not require immediate control action but requires the applicable entity to begin evaluations necessary to take control actions. These evaluations may include but are not limited to verifying the limit, measurement, or performing a on-line power flow study.

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Kathleen Goodman	
Organization:	ISO New England	
Telephone:	(413) 535-4111	
E-mail:	kgoodman@iso-ne.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)			
Group Name:			
Lead Contact:			
Contact Organization:			
Contact Segment:			
Contact Telephone:			
Contact E-mail:			
Additional Member Name	**Additional Member Organization**	**Region***	**Segment***

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments: We agree that good utility practice and procedures should not be included in standards. However, care should be taken not to remove coordination requirements which are in fact necessary to reliability planning and operation.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: We strongly disagree with this idea. Respecting SOLs is a fundamental operational requirement. Transmission Operators must be required to closely montior their area; failing to do so may ultimately lead to cascading failures, as was witnessed on August 14. SOLs, left unchecked, will become an IROL, which is why it is imperative that all SOLs be monitored and respected at the TOP level.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments: This may be a reasonable approach. However, the SAR DT may want to consider if they then need to pass all comments dealing specifically with the standards on to the Standards Drafting team from this process.

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

Some of the standards included in this SAR for revision appear to create a conflict with other ongoing SAR and Standard drafting activites. We are becoming more and more concerned about the parallel changes taking place.

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR: No.

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments:

7. Do you agree with the scope of this SAR?

☐ Yes

☒ No

Comments: Please see response to Q#4.

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments: ISO New England supports Quebec's proposal not to be subjected to BAAL-007-1 requirements because of their single BA Interconnection status.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
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E-mail: bthumm@itctransco.com		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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- COM-002-2 Communications and Coordination
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- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments:

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: While SOLs may be local in nature, the mitigation of SOL violations has the potential to impact several entities of the functional model - oftentimes from different companies. Without a standard, it will be difficult to properly justify actions taken to mitigate SOL violations.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR:

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

   ☒ Yes

   ☐ No

   Comments:

7. **Do you agree with the scope of this SAR?**

   ☒ Yes

   ☒ No

   Comments: Except for not addressing the SOL issue described above.

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

   ☐ Regional Variances

   ☐ Business Practices

   Comments:

9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

   Comments:

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information

(Complete this page for comments from one organization or individual.)

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Telephone:	204-487-5445
E-mail:	mdrheault@hydro.mb.ca

NERC Region		Registered Ballot Body Segment
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☒ MRO	☒	3 — Load-serving Entities
☐ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☒	5 — Electric Generators
☐ SERC	☒	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
☐ WECC	☐	8 — Small Electricity End Users
☐ NA – Not Applicable	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☒ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments: If the "procedures and good utility practice" are enforceable, the above requirements should remain in the standards. If these requirements are removed from the standard, where will the reference documents be located? An attachment to the Standard or a separate manual not quickly and easily accessible to those who need it?

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: If the "procedures and good utility practice" are enforceable, the above requirements should remain in the standards. If these requirements are removed from the standard, where will the reference documents be located? An attachment to the Standard or a separate manual not quickly and easily accessible to those who need it?

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

The following standards should be added to the SAR:

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments: The standards must be revised to clearly define the responsible entity for each requirement. There can't be any room for a requirement to fall through the cracks because the assignment of responsibility is not clear. Redundancy between Standards does not mitigate the risk of inadequate assignment of responsibility, but rather it may increase the likelihood that responsible entities assume that the requirements are met by others.

7. Do you agree with the scope of this SAR?

☒ Yes

☐ No

Comments:

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments:
Specific to COM-001-1 Telecommunications:

In general, we support the proposed revisions to this standard with the following exceptions.

Periodicity and type of testing should not be defined explicitly in the standard. The onus must be placed on each organizaton to determine the periodicity and testing requirements as necessary to meet expected performance criteria. Such requirements would require regular review and adjustment to address changing conditions.

Appendix B - FERC Order 693: We are concerned that the proposed expansion of the Standard to included Generator Operators and Distribution Providers is unachievable within a reasonable period of time relative to ongoing efforts to comply with current standards. i.e. - too much too fast.

Specific to TOP-005 Operational Reliability Information

If the proposed changes are adopted, only one requirement R3 remains in this standard. This requirement involves Balancing Authorities (BAs)and Transmission Operators (TOs) supplying on-line information to associated BAs and TOs for reliability assessments and coordinated operations. This same information is also transmitted to the Reliability Coordinators (RCs)via requirement R1. (which is now to be transferred to and covered by IRO-010-1).

If the RCs are receiving all the required reliability data anyway, why can't all concerned BAs and TOs get this same data from the RCs instead of directly from the concerned utility? Won't all BAs and TOs be required to send reliability data the closest RCs, even if they are not already a direct or associate member of any established RC?

Keeping TOP-005 only for R3 opens the door to potential reliability analysis and data being developed and transmitted between interconnected BAs and TOs that is NOT also transmitted to RCs. It may be better to make TOP-005 R3. part of another standard (such as IRO-010) to ensure RCs are properly informed, and then eliminate TOP-005 altogether.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: NSRS

Lead Contact: Ken Goldsmith

Contact Organization: MRO

Contact Segment: 10

Contact Telephone: 319-786-4167

Contact E-mail: kengoldsmith@alliantenergy.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Eric Ruskamp	Lincoln Electric System	MRO	10
Joe Knight	Great River Energy	MRO	10
Terry Bilke	MISO	MRO	10
Mike Brytowski	Midwest Reliability Organization	MRO	10
David Rudolph	Basin Electric Power Cooperative	MRO	10
Pamela Oreschnick	Xcel Energy	MRO	10
Robert Coish	Manitoba Hydro	MRO	10
Neal Balu	WPSR	MRO	10
Al Boesch	NPPD	MRO	10
Carol Gerou	Minnesota Power	MRO	10
Jim Haigh	WAPA	MRO	10
Todd Gosnel	OPPD	MRO	10
27 additional MRO members	Not named above	MRO	10

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

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- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments: While we agree that the procedures and good utility practices do not necessarily need to be in the standard itself, the reference documents must be issued concurrent with the implementation of the revised standard. There is a great deal of information that is very useful for the utilities implementing the standards.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☒ Yes

   ☐ No

   Comments: A System Operating Limit (SOL) does not necessarily need to be included in the standard itself, but the literature on Good Utility Practice must be issued concurrent with the implementation of the revised standard. There is a great deal of information that is very useful for the utilities implementing the standards.

   To aid understanding of a System Operating Limit (SOL), it would be very helpful to add some examples of a SOL in the Glossary of Terms.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there any standards included in the SAR that shouldn't be included?**

The following standards were included in the SAR and should be removed: There are several TOP standards currently under revision in other SAR's. There must be clear coordination between the Drafting Teams of the various SAR's as they are revising the Reliability Standards.

5. **Are there standards that should be added to the SAR?**

The following standards should be added to the SAR:

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments: The current versions of the standards are very voluminous and confusing. These revisions should remove the ambiguity and lead to a small set of quality reliability related requirements to be complied with.

7. Do you agree with the scope of this SAR?

☒ Yes

☐ No

Comments: The current versions of the standards are very voluminous and confusing. These revisions should remove the ambiguity and lead to a small set of quality reliability related requirements to be complied with.

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments: We are not aware of any at this time, since we do not know the detailed changes and wording that will be in the Reliability Standards. It is imperative to include red-line versions of the revised standards to allow determination of what needs to be included in the reference documents.

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments: As the standards are revised, it is necessary to insure there is, at a minumim, one measurement for each requirement. If a measure can not be determined for a requirement, the requirement should be rewritten or deleted.

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	James Castle	
Organization:	New York Independent System Operator	
Telephone:	518-356-6244	
E-mail:	jcastle@nyiso.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
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☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☒ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments: Each case should be reviewed on an individual basis. It was not clear in the examples you provided. It is possible that some procedures may need to be reworded into standard language and for others it may be appropriate to move to a reference document.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: SOLs should be retained as part of the NERC Standards. The NYISO does not believe that SOLs are only important to local operations. SOLs also occur on BPS facilities and can cause reliability issues outside of the local utility operations, without being an IROL.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments: This may be a reasonable approach. The NYISO would recommend that all subsequent comments be provided to the Standards Drafting Team for consiration in revising the standards.

4. **Are there any standards included in the SAR that shouldn't be included?**

The following standards were included in the SAR and should be removed: We do agree that this SAR appears to cover the right set of standards. However, it potentially conflicts with other SARs and draft standards.

The Operating Personnel Communications Protocol (OPCP) SAR is proposing to modify COM-1-1, COM-002-2, TOP-001-1, TOP-002-2, TOP-007-0, TOP-008-0 standards. All of these standards are proposed to be modified in this SAR. How does this SAR Drafting Team propose to coordinate with the OPCP SAR drafting team. It seems like this would be difficult to accomplish and that one SAR should be delayed.

The Operate within Interconnected Operating Limits Standard Drafting team is in the process of modifying the TOP-003, TOP-005, and TOP-006 standards. Assuming these standards are eventually approved, this SAR will have to be modified to reflect the new versions of the standards. Again, this SAR should be delayed until the Operate within Interconnected Operating Limits Standards have completed the ballot process.

Finally, System Personnel Training drafting team is proposing to eliminate PER-001 through PER-004. This SAR would have to be updated to reflect those changes. Again this SAR should be delayed until these standards are balloted.

5. **Are there standards that should be added to the SAR?**

The following standards should be added to the SAR: No.

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

☒ Yes

☐ No

Comments:

7. **Do you agree with the scope of this SAR?**

☒ Yes

☐ No

Comments:

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

☐ Regional Variances

☐ Business Practices

Comments:

9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

Comments: The SAR proposes to add the language "without delay" to a number of requirements. We are concerned that this wording could be interpreted in a standard to require the need for immediate control action. We propose that the standard drafting team should clarify that the "without delay" language does not require immediate control action but requires the applicable entity to begin evaluations necessary to take control actions. These evaluations may include but are not limited to verifying the limit, measurement, or performing a on-line power flow study.

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☒	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: **NPCC CP9 Reliability Standards Working Group**

Lead Contact: **Guy V. Zito**

Contact Organization: **Northeast Power Coordinating Council**

Contact Segment: **10**

Contact Telephone: **212-840-1070**

Contact E-mail: **gzito@npcc.org**

Additional Member Name	Additional Member Organization	Region*	Segment*
Ralph Rufrano	New York Power Authority	**NPCC**	1
Roger Champagne	TransEnergie HydroQuebec	**NPCC**	1
Ron Falsetti	The IESO, Ontario	**NPCC**	2
Kathleen Goodman	ISO New England	**NPCC**	2
Al Adamson	New York State Reliability Council	**NPCC**	10
Greg Campoli	New York ISO	**NPCC**	2
Guy V. Zito	NPCC	**NPCC**	10
Donald Nelson	MA DPUC	**NPCC**	9

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments: We agree that good utility practice and procedures should not be included in standards. However, care should be taken not to remove coordination requirements which are in fact necessary to reliability planning and operation.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments: We strongly disagree with this idea. Respecting SOLs is a fundamental operational requirement. Transmission Operators must be required to closely montior their area; failing to do so may ultimately lead to cascading failures, as was witnessed on August 14. An SOLs, left unchecked, will become an IROL, which is why it is imperative that all SOLs be monitored and respected at the TOP level.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments: This may be a reasonable approach. However, the SAR DT may want to consider if they then need to pass all comments dealing specifically with the standards on to the Standards Drafting team from this process.

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

Some of the standards included in this SAR for revision appear to create a conflict with other ongoing SAR and Standard drafting activites. We are becoming more and more concerned about the parallel changes taking place.

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR: No.

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☒ Yes

☐ No

Comments:

7. Do you agree with the scope of this SAR?

☐ Yes

☒ No

Comments: Please see response to Q#4.

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments: HQT(Quebec) wishes to proposed that the Province of Quebec not be subjected to BAAL-007-1 requirements and so not be subject to compliance to that standard. Since Quebec is a single BA Interconnection, BAAL-007 is not relevant. For Quebec, BAAL-008 is the Standard that is more relevant for reliable operation.

Quebec proposes to follow the rest of BAAL-008 to BAAL-011 and would be willing to participate in the field test for those Standards.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Public Service Commission of South Carolina

Lead Contact: Phil Riley

Contact Organization: Public Service Commission of South Carolina

Contact Segment: 9

Contact Telephone: 803-896-5154

Contact E-mail: philip.riley@psc.sc.gov

Additional Member Name	Additional Member Organization	Region*	Segment*
Mignon L. Clyburn	Public Service Commission of SC	SERC	9
Elizabeth B. "Lib" Fleming	Public Service Commission of SC	SERC	9
G. O'Neal Hamilton	Public Service Commission of SC	SERC	9
John E. "Butch" Howard	Public Service Commission of SC	SERC	9
Randy Mitchell	Public Service Commission of SC	SERC	9
C. Robert "Bob" Moseley	Public Service Commission of SC	SERC	9
David A. Wright	Public Service Commission of SC	SERC	9

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

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- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments:

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☐ No

   Comments:

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

   ☐ No

   Comments:

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed: None

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR: None

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

   ☒ Yes

   ☐ No

   Comments:

7. **Do you agree with the scope of this SAR?**

   ☒ Yes

   ☐ No

   Comments:

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

   ☐ Regional Variances

   ☐ Business Practices

   Comments: None

9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

   Comments: None

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
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☐ **NPCC**	☐	4 — Transmission-dependent Utilities
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☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: Southern Company Transmission

Lead Contact: Roman Carter

Contact Organization: Southern Company Transmission

Contact Segment: 1

Contact Telephone: 205.257.6027

Contact E-mail: jrcarter@southernco.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Jim Busbin	Southern Co. Transmission	SERC	1
J.T. Wood	Southern Co. Transmission	SERC	1
Marc Butts	Southern Co. Transmission	SERC	1
Raymond Vice	Southern Co. Transmission	SERC	1
Jim Griffith	Southern Co. Transmission	SERC	1

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments:

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☒ Yes

   ☒ No

   Comments: There are many Standard requirements outside the scope of this SAR which require the RC to "monitor" potential SOLs.

   As an example, IRO-003, R1 says each Reliability Coordinator shall monitor all Bulk Electric System facilities to ensure the RC is able to determine any potential System Operating Limit. If this SAR removes the standards in scope that mention SOLs but leaves IRO-003, R1, to be enforced, then ambuiguity will result.

   IRO-003, R2 says each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL. Again, it appears in other standards (outside the scope of this SAR) that the RC is responsible (enforceble requirement) for being aware of preliminary events that could lead to an SOL.

   Additionally, IRO-002, R6 also contains such references to SOLs as well as other IRO Standards. Therefore, it appears the scope of the SAR should be broadened to include other standard requirements not contained in this SAR.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

☒ Yes

☒ No

Comments: This SAR does not provide the referenced assessments the SAR drafting team has made on comments contained in Appendix B. Therefore, we can not agree or disagree with the team's assessment.

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed:

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR: IRO-002, IRO-003, IRO-005, IRO-006. However, there could be others.

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

   ☒ Yes

   ☐ No

   Comments:

7. **Do you agree with the scope of this SAR?**

   ☐ Yes

   ☒ No

   Comments: The SAR needs to be broadened in scope to cover all standard requirements that contain references of the RC being responsible for SOLs and not just a subset of standards.

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

   ☐ Regional Variances

   ☐ Business Practices

   Comments:

9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

Comments: It is recommended that the drafting team members review all alleged duplications closely to be sure that the true meaning of the duplicated statement is the same as the orginal statement before being deleted. There could be instances where the words are the same but the meaning behind the duplication could be different.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Alan Gale	
Organization:	City of Tallahassee (TAL)	
Telephone:	(850) 891-3025	
E-mail:	galea@talgov.com	
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
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Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

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- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☒ Keep these items as requirements in standards

   ☒ Move these items into references

   Comments: I am all for removing items that are "not standards" from the standards. However, references can be hard to keep track of. And they will "creep" into standard via the Readiness Assessment process.

   Each "requirement" up for deletion should be reviewed individually. Even the SAR drafting team disagrees on them. The example cited above (TOP-001-1, R7) is slated for revision in the Detailed Description portion of the SAR itself. The TOP-002-2, R2 should be removed.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☒ No

   Comments:
   - Without a standard requiring action on SOL's, many entities will live with them in the hope that nothing else will happen.
   - If you make the RC aware of small problems (SOL), they can be corrected before they are big problems (IROL).
   - The determination of whether an SOL is an IROL is made by the RC. If there is no notification, how can he make that determination?
   - Some coordination of SOL remediation may need to occur between entities. The corrective action I want to take may put my neighbor in extremise. The coordination is best done while keeping the RC informed.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☒ Yes

☐ No

Comments:

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed: None

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR: None

6. **Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?**

   ☒ Yes

   ☐ No

   Comments:

7. **Do you agree with the scope of this SAR?**

   ☒ Yes

   ☐ No

   Comments:

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.**

   ☐ Regional Variances

   ☐ Business Practices

   Comments: None

9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

   Comments: None

Please use this form to submit comments on the proposed Real-time Transmission Operations and Balancing of Load and Generation SAR. Comments must be submitted by **June 13, 2007**. Please submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP & BA" in the subject line. If you have questions please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net

Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region		**Registered Ballot Body Segment**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)	
Group Name:	WECC Reliability Coordination Comments Work Group (RCCWG)
Lead Contact:	Nancy Bellows
Contact Organization:	WACM
Contact Segment:	10
Contact Telephone:	970-461-7246
Contact E-mail:	bellows@wapa.gov

Additional Member Name	Additional Member Organization	Region*	Segment*
Tom Botello	SCE	WECC	10
Bob Johnson	PSC	WECC	10
Frank McElvain	RDRC	WECC	10
Greg Tillitson	CMRC	WECC	10

*If more than one Region or Segment applies, indicate the best fit for the purpose of these comments. Regional acronyms and segment numbers are shown on prior page.

Background Information

The Real-time SAR for Transmission Operations and Balancing of Load and Generation includes revising the following standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Please review the SAR and then submit your comments on this form and e-mail to sarcomm@nerc.net by **June 13, 2007** with the words "**Real-time TOP & BA**" in the subject line.

You do not have to answer all questions. ***Insert a "check" mark in the appropriate boxes by clicking the gray areas.***

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

   ☐ Keep these items as requirements in standards

   ☐ Move these items into references

   Comments: The WECC RCCWG believes that some provisions of TOP-001-1 R1 are standard requirements, and that whether TOP-002-2 R2 is a standard requirement is less clear. The group agrees that in order to be a standard requirement there needs to be a link to an impact on the Bulk Electric System. The requirements need to be reworded to be measurable and substantiable.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on "good utility practice." Do you agree?**

   ☐ Yes

   ☐ No

   Comments: While it is true that some SOLs do not have Bulk Electric System impact, such as a wave trap or customer transformer overload (local issues), others may lead to an impact on the Bulk Electic System. The group feels that if it can be shown through studies that a SOL does not have an impact on the Bulk Electic System, that particular SOL could be exempted from standards requirements. The group also questions whether a SAR without Bulk Electric System impact, but with potential local impact that would require a NERC disturbance report should be a standard requirement.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the standard drafting team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the standard drafting team?**

   ☐ Yes

   ☐ No

   Comments: The references, such as FERC Order 693, are so detailed that the WECC RCCWG does not believe the group can comment on the standard drafting team assessment of those comments.

4. **Are there any standards included in the SAR that shouldn't be included?**

   The following standards were included in the SAR and should be removed: None are currently identified, but some may become apparent later.

5. **Are there standards that should be added to the SAR?**

   The following standards should be added to the SAR: None are currently identified, but some may become apparent later.

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

☐ Yes

☐ No

Comments: The WECC RCCWG believes that some of the standard requirements need to be clarified.

7. Do you agree with the scope of this SAR?

☐ Yes

☐ No

Comments:

8. If you aware of any regional variances or business practices that should be developed in association with this SAR please list them here.

☐ Regional Variances

☐ Business Practices

Comments:

9. If you have any other comments on this SAR that you haven't identified above, please provide them here.

Comments: The WECC RCCWG suggests differentiating TOP directives from Reliability Coordinator directives. This may be done with specific language. It should be clear to the entity receiving a directive who issued that directive. It may be beneficial to have a NERC definition for a "Reliability Coordinator Directive" and a "Transmission Operator Directive".

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on First Draft of the Real-time Operations SAR for Transmission Operations and Balancing of Load and Generation

The Real-time Operations SAR requesters thank all stakeholders who submitted comments on Draft 1 of the Real-time Operations SAR. This SAR was posted for a 30-day public comment period from May 15 through June 13, 2007. The requesters asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 23 sets of comments, including comments from 62 different people from 43 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the SAR drafting team is recommending that the SAR be re-posted to include specific issues that were pointed out by the commenters:

- Inclusion of IRO-004, -005 & -006 in the scope.
- Correction to the reference in TOP-001-1, R2.
- Correction to the reference in TOP-002-2, R3.
- Clarified the reason for recommending the deletion of TOP-002-2, R8.
- Corrected the reference in TOP-002-2, R10.
- Removed the recommendation for deleting TOP-002-2, R11.
- Rewording of the recommendation in TOP-002-2, R14 & R15.
- Clarified the deletion requested in TOP-004-1, R1.

Based on stakeholder comments, the SAR DT is proposing to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Real-time_Operations_Project_2007-03.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Thad Ness	AEP	✓									
2.	Anita Lee (G2)	AESO		✓								
3.	Jeffrey V. Hackman	Ameren										
4.	Jason Shaver	ATC LLC										
5.	David Rudulph (G1)	Basin Electric Power Coop.										✓
6.	Brent Kingsford (G2)	CAISO		✓								
7.	Anthony Alford	CenterPoint Energy										
8.	Alan Gale (G1)	City of Tallahassee					✓					
9.	Greg Tillitson (G4)	CMRC										✓
10.	Gregory D. Rowland	Duke Energy	✓		✓							
11.	Ed Davis	Entergy Services, Inc.										
12.	Will Franklin	Entergy Services, Inc.										
13.	Steve Myers (G2)	ERCOT		✓								
14.	Doug Hohlbaugh	FirstEnergy	✓		✓		✓	✓				
15.	John Reed	FirstEnergy	✓		✓		✓	✓				
16.	David Folk	FirstEnergy	✓		✓		✓	✓				
17.	Ed DeVarona	Florida Power & Light	✓									
18.	Eric Senkowicz	FRCC										✓
19.	Joe Knight (G1)	Great River Energy										✓
20.	Roger Champagne (I) (G3)	Hydro-Québec TransÉnergie (HQT)	✓									
21.	Ron Falsetti (I) (G2) (G3)	IESO		✓								
22.	Matt Goldbert (G2)	ISO-NE		✓								
23.	Kathleen Goodman (I) (G3)	ISO-NE		✓								
24.	Brian Thumm	ITC Transco	✓									
25.	Eric Ruskamp (G1)	Lincoln Electric System										✓
26.	Donald Nelson (G3)	MA DPUC									✓	

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
27.	Michelle Rheault	Manitoba Hydro	✓		✓		✓	✓				
28.	Robert Coish (G1)	Manitoba Hydro										✓
29.	Terry Bilke (G1)	Midwest ISO										✓
30.	Mike Brytowski (G1)	Midwest Reliability Organization										✓
31.	Carol Gerou (G1)	Minnesota Power										✓
32.	Bill Phillips (G2)	MISO		✓								
33.	Guy V. Zito (G3)	NPCC										✓
34.	Al Adamson(G3)	NY State Reliability Council										✓
35.	Jim Castle (I) (G2)	NYISO		✓								
36.	Greg Campoli (G3)	NYISO		✓								
37.	Ralph Rufrano (G3)	NYPA	✓									
38.	Todd Gosnell (G1)	OPPD										✓
39.	Alicia Daugherty (G2)	PJM		✓								
40.	Bob Johnson (G4)	PSC										✓
41.	Philip Riley	Public Service Commission of SC									✓	
42.	Mignon L.Clyburn	Public Service Commission of SC									✓	
43.	Elizabeth B. Fleming	Public Service Commission of SC									✓	
44.	G. O’Neal Hamilton	Public Service Commission of SC									✓	
45.	John E. Howard	Public Service Commission of SC									✓	
46.	Randy Mitchell	Public Service Commission of SC									✓	
47.	C. Robert Moseley	Public Service Commission of SC									✓	
48.	David A. Wright	Public Service Commission of SC									✓	
49.	Frank McElvain (G4)	RDRC										✓
50.	Tom Botello (G4)	SCE										✓
51.	Steve Wallace	Seminole Electric Coop.				✓						
52.	Roman Carter	Southern Company Transmission	✓									
53.	Jim Busbin	Southern Company Transmission	✓									
54.	J.T. Wood	Southern Company Transmission	✓									
55.	Marc Butts	Southern Company Transmission	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	Raymond Vice	Southern Company Transmission	✓									
57.	Jim Griffith	Southern Company Transmission	✓									✓
58.	Charles Yeung (G2)	SPP		✓								
59.	Nancy Bellows (G4)	WACM										✓
60.	Jim Haigh (G1)	WAPA										✓
61.	Neal Balu (G1)	WPSR										✓
62.	Pamela Oreschnick (G1)	Xcel Energy										✓

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – MRO Members
G2 – IRC Standards Review Committee (IRC SRC)
G3 – NPCC CP9 Reliability Standards Working Group (NPCC CP9)
G4 – WECC Reliability Coordination Comments Work Group (RCCWG)

Index to Questions, Comments, and Responses

1. **The TOP standards seem to refer in many places to procedures and good utility practice as opposed to true standards. (See TOP-001-1, R7 and TOP-002-2, R2.) Should these items remain as standard requirements or should procedures and good utility practices be removed from the standards and be placed into reference documents?**

Summary Consideration: The SAR drafting team appreciates that the industry is near consensus on the removal of 'good utility practices' from NERC standards. We recognize that care must be taken to continue to require compliance with a necessary and sufficient set of standards for the continued reliable operation of the Bulk Electric System while moving some of the existing language from standards into reference documents. We also note that reference documents must be made readily available for continued usage. Our detailed responses are listed with each comment.

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
ATC LLC	☑		Standards define "good utility practices" therefore it's our opinion that these requirements should remain.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team appreciates your comment and agrees that any requirement that is strongly linked to assuring reliability, very specific, and consistently measurable should remain in the standards. General statements that are typically hard if not impossible to measure should be removed from the standards. 'Good utility practice' spans a wide range of acceptable practices, while standards set a specific bar that all must meet. Standards should not codify procedures that are simply one way of meeting a standard requirement.			
Manitoba Hydro	☑		If the "procedures and good utility practice" are enforceable, the above requirements should remain in the standards. If these requirements are removed from the standard, where will the reference documents be located? An attachment to the Standard or a separate manual not quickly and easily accessible to those who need it?
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team has not considered the ultimate location of any reference material. The SAR DT will pass this comment on to the NERC staff in order to come to a reasoned conclusion. One good location that could be considered would be a 'references' section on the NERC web site. The intent should be to have the reference documents readily available for consultation as well as for use in developing training.			
FirstEnergy	☑		FirstEnergy agrees in general that Good Utility Practices in and of themselves do not belong in the standards. However, for the two examples cited we believe these are important processes for ensuring a reliable electric system and therefore should remain within the reliability standards. Exclusion of requirments based on Good Utility Pratices will

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
			need to be evaluated and addressed on a case by case basis and commented on via the standard drafting process.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team agrees with the concept of addressing these issues on a case by case basis. The examples cited may ultimately be considered to be requirements; the team was attempting to amplify the concept of removing redundant and superfluous requirements to help deal with the unavoidable angst that was expected to occur due to the idea of removing some standards when this SAR was posted for comments. We will pass your comments along to the eventual Standards Drafting Team.			
City of Tallahassee	☑	☑	I am all for removing items that are "not standards" from the standards. However, references can be hard to keep track of. And they will "creep" into standard via the Readiness Assessment process. Each "requirement" up for deletion should be reviewed individually. Even the SAR drafting team disagrees on them. The example cited above (TOP-001-1, R7) is slated for revision in the Detailed Description portion of the SAR itself. The TOP-002-2, R2 should be removed.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team agrees with your comments. Each requirement will be reviewed individually to assure that it is necessary and not redundant. We had debated whether to revise or delete TOP-001-1, R7 and wrote it up to revise it for now. These comments will be passed on to the Standards Drafting Team.			
Duke Energy	☑	☑	Where the identification of procedures and good utility practice bring clarity to TOP requirements, they should be retained, although not as separate requirements.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team agrees with your comments. The structure of NERC standards are such that the usual background and explanatory material that once were contained in the NERC Operating Policies have no formal spot for archiving these types of issues. The Standards Drafting Team should work with NERC staff to assure that the clarity remains while not inadvertently retaining additional, unnecessary requirements.			
NYISO	☑	☑	Each case should be reviewed on an individual basis. It was not clear in the examples you provided. It is possible that some procedures may need to be reworded into standard language and for others it may be appropriate to move to a reference document.
Response: The general consensus of the commenters was to remove 'good utility practice' from the standards. The SAR drafting team agrees with your comments. Industry comments indicate that each and every requirement that is necessary to			

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
assure continued reliable operation of the Bulk Electric System should be retained. The SAR DT will pass this comment on to the NERC staff in order to come to a reasoned conclusion on the topic of a reference document. One good location that could be considered would be a 'references' section on the NERC web site. The intent should be to have the reference documents readily available for consultation as well as for use in developing training. It is also clear that each individual change will need an explanation in order to gain industry consensus. The SAR drafting team found that our deliberations tended to link the various requirements across several standards, and that only by considering several at once did redundancies appear. It will behoove the Standards Drafting Team and NERC to fully explain the need for each change in order to help the balloting group gain confidence that the course being plotted will result in continued reliable operation of the Bulk Electric System.			
IESO			We concur that good utility practices and administrative procedures should not be included in standards. Nonetheless, we suggest the SDT to assess which of the existing requirements, including the procedural ones, are indeed actions needed to preserve reliability and hence keep them in the standards. While we agree that TOP-002-2, R2 may be removed, we do not agree that TOP-001-1 R7 should be removed since the notification and coordination of generation and transmission outages are necessary to ensure that reliability impact of the planned removal of the BES facility is assessed. It is not an administrative procedure or good utility practice; it is a reliability requirement.
Response: The SAR drafting team thanks you for your comments and has taken them under advisement. The reason that the SAR includes the elimination of the examples cited is to remove redundancy. In the specific case of TOP-001-1, R7, the requirement is basically "don't burden your neighbors" and "tell the RC what is going on". The additional language in R7 and its sub-requirements is unnecessary. TOP-003-0, R1.2 already requires data sharing to enable outage coordination to avoid burdening neighbors. TOP-001-1, R3 requires all BA/TOP/GOs to comply with RC reliability directives. Finally, IRO-004-1, R6 requires the RC to issue reliability directives to BA/TOP/GOs if the results of their studies indicate potential SOL or IROL violations. Therefore, this issue is already covered in other areas and is redundant in this location and should be removed. However, the Standards Drafting Team will make the final decision on the form that the standard will take when it goes to ballot.			
HQT			We agree that good utility practice and procedures should not be included in standards. However, care should be taken not to remove coordination requirements which are in fact necessary to reliability planning and operation.

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
ISO-NE			We agree that good utility practice and procedures should not be included in standards. However, care should be taken not to remove coordination requirements which are in fact necessary to reliability planning and operation.
NPCC CP9 RSWG			We agree that good utility practice and procedures should not be included in standards. However, care should be taken not to remove coordination requirements which are in fact necessary to reliability planning and operation.
Response: The team thanks you for your comments and is in agreement that reliable interconnected operation requires coordination which would continue to be enforced by specific standards.			
IRC SRC			Good utility practices and procedures should not be included in standards. They are vague statements and do not belong in the standards even as a reference. If good utility practice statements were acceptable there would only be a need for one requirement and that is that all entities shall institute good utility practice. True standards need to be developed and superfluous information should not remain in the standards.
Response: The SAR drafting team thanks you for your support on this issue. The sentiment expressed in your comment is exactly what we were thinking in asking this question. NERC standards must have a strong link to assuring reliability, be very specific, and consistently measurable.			
WECC RCCWG			The WECC RCCWG believes that some provisions of TOP-001-1 R1 are standard requirements, and that whether TOP-002-2 R2 is a standard requirement is less clear. The group agrees that in order to be a standard requirement there needs to be a link to an impact on the Bulk Electric System. The requirements need to be reworded to be measurable and substantiable.
Response: The SAR drafting team thanks you for your comments and is in agreement. Your comment identified yet another requirement which needs scrutiny if it is to remain in NERC standards.			
Entergy (Franklin)		☑	Move to reference documents or eliminate 'good practices' from standards, and also eliminate redundant requirements.
ERCOT		☑	Such information is of value and should not be lost, but does not belong in a Standard. A Standard must apply continent-wide and not be of the nature of dictating any particular practice or procedure.

Question #1			
Commenter	**Keep these items as requirements in standards**	**Move these items into references**	**Comment**
MRO		☑	While we agree that the procedures and good utility practices do not necessarily need to be in the standard itself, the reference documents must be issued concurrent with the implementation of the revised standard. There is a great deal of information that is very useful for the utilities implementing the standards.
FRCC		☑	Subjective commentary that is not measurable or enforceable should be removed from the standards and placed in the Reliability Readiness Evaluation and Improvement Program Reference Manual or something similar.
Response: The SAR drafting team agrees with your comments. The decision of when or whether to issue reference documents will be passed to the Standards Drafting Team and NERC staff. We agree that the concepts included in this SAR which may be moved to reference material are of such importance that the reference material publishing schedule will need to be prompt in order to minimize concern over the potential loss thereof.			
AEP		☑	
Ameren		☑	
Entergy (Davis)		☑	
ITC Transco		☑	
PSC SC		☑	
SOCO Transmission		☑	
Response: The SAR drafting team thanks you for your support on this issue.			
CenterPoint			No comment.

2. **The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on 'good utility practice'. Do you agree?**

Summary Consideration: Based on stakeholder comments, the SAR DT is proposing to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs.

The SAR DT believes that the sole purpose of NERC standards is to ensure BES reliability. The majority of the team believes that NERC standards are not intended to cover local events which have no impact on neighboring system reliability. The requirements currently embedded in NERC standards exist due to many reasons. During the V0 drafting effort massive duplication of requirements was noticed by the drafting team but left within the standards due to the mandate to "not change anything, just re-format it for standards".

SOLs, by NERC's own definition, are not cascading events. This does not mean that they are not important (and RCs are still required to monitor them) but there is no reliability reason to require some entity to not violate an SOL. Interconnected Transmission Systems must continue to operate so as not to burden their neighbors or risk BES reliability. These are fundamental requirements for continued reliable operation of the BES. If you follow all of the other standards for planning and operational planning, such as FAC-011 and the IRO standards, you should never find yourself within one Contingency of violating an IROL.

Question #2			
Commenter	**Yes**	**No**	**Comment**
AEP		☑	We disagree with this statement. Just what does the SAR DT consider to be a true BES reliability issue? The team's opinion seems contradictory to NERC's efforts to have the Regions agree that all non-radial transmission facilities 100 kV and above are Bulk Electric System facilities. On one end of the spectrum there is a NERC effort to expand the definition and size of BES. Then you efforts like this SAR to reduce the size and scope. While the most severe and significant BES reliability issue may be IROL violations (IROL violations can lead to instability, uncontrolled separation, or cascading outages), that surely is not the only reliability issue. Multiple SOL events can lead to a situation where you have a new, non-studied IROL. Should we not operate the system such to prevent us from entering or approaching IROL limits? If the only limits that have applicable Reliability Standards is IROLs, then are we not setting up the system to approach the "edge of the cliff" before we take appropriate defensive action? While we agree not all

Question #2			
Commenter	**Yes**	**No**	**Comment**
			SOLs have a significant impact on the overall reliability of the BES, we do not agree that means all requirements related to SOLs should be removed from the NERC Standards. That would be a move towards less reliability in the future, not a step towards improving reliability. And just what is meant by local utility operations not being a true BES reliability issue. If the system is not operated to respect SOLs, then that could jeopardize a firm power purchase from a distance resource via firm transmission service that a "local utility" is relying upon. Loss of that firm power purchase, could lead to having to shed customer load? Why is that not a BES reliability issue? Isn't that one of the reasons the BES exists is to support such commerce? Violating SOLs could also result in the tripping of generation outlets, resulting in loss of generation. That too is not a BES reliability issue? Before we could support removing requirements related to SOLs, the SAR DT team would need to provide a definition of what exactly is considered a BES reliability issue. Most of the TLRs that are implemented today are for relieving SOLs not IROLs. Therefore, removing requirements related to SOLs would be in direct conflict with current practices and does not improve the reliability practices from what we have today. At a minimum, RCs and TOPs need to monitor and know the EHV system SOLs and ensure operation within those SOLs and to monitor and operate to other SOLs as specified in the agreements between the RC and TOPs and BAs (see ORG-021-1 R3). While it is not practical or necessary to ticket every car speeding on the freeway, on the contrary it is also not practical or necessary to remove the speedometer from the cars. We feel that the requirements for the SOL are like the speedometers; therefore, removing requirements related to SOLs is inappropriate and could lead to less reliable operations.
Response: The SAR drafting team is utilizing the definition of SOL developed in FAC-011-1 which states that: R1.2 …SOLs shall not exceed associated Facility Ratings. R2.1 …In the pre-contingency state, the BES shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage, and stability limits. R2.2 Following the single Contingencies identified in Requirements 2.2.1 through 2.2.3, the system shall demonstrate transient, dynamic, and voltage stability; all Facilities shall be operating within their Facility Ratings; and within their thermal, voltage, and stability limits; and Cascading Outages or uncontrolled separation shall not occur. FAC-011-1 also requires that the RC; R1.3**.** Include a description of how to identify the subset of SOLs that qualify as IROLs.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
The SAR drafting team concludes from this that SOLs, "… while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on 'good utility practice'." Nor do we find anything in your comments that leads us to believe otherwise. According to FAC-011-1, unless and until SOLs qualify as IROLs they are not a threat to BES reliability and do not require RCs to do more than monitor their status.			
ATC LLC		☑	ATC does not agree with SAR DT that SOLs are only important to local operations and that they should be removed from these standards. If SOLs are removed from NERC standards then any real-time identifications of an SOL that becomes an IROL will be difficult if not impossible to determine.
Response: As noted above, the SAR drafting team is utilizing the definition of SOL developed in FAC-011-1 which requires that the RC ; R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs. The SAR drafting team concludes from this that SOLs can either be effectively identified prior to the time they become IROLs, or they will be flagged for RC attention since they fail the requirement of R1.3 and demand special processing from the TOP and RC. According to FAC-011-1, unless and until SOLs qualify as IROLs or are identified as impossible to classify, they are not a threat to BES			
Duke Energy		☑	Where SOLs impact the Bulk Electric System, they are a reliability issue and should not be moved into guides or other reference documents.
Response: As noted above, the SAR drafting team is utilizing the definition of SOL developed in FAC-011-1 which requires that the RC: R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs. The SAR drafting team concludes from this that SOLs which will impact the reliability of the BES will be identified as IROLs and treated appropriately as per the requirements of IRO-005-2, IRO-006-3 and others.			
IESO		☑	We strongly disagree with this notion. Respecting SOLs and mitigating their violations are fundamental to the reliable operation of the transmission operator's area which may ultimately affect the interconnected system. And since IROLs are a subset of SOLs, and that some SOLs may become IROLs as system condition changes, it is imperative that all SOLs be monitored and observed at all time.
City of Tallahassee		☑	- Without a standard requiring action on SOL's, many entities will live with them in the hope that nothing else will happen. - If you make the RC aware of small problems (SOL), they can be corrected before they are big problems (IROL).

Question #2			
Commenter	**Yes**	**No**	**Comment**
			- The determination of whether an SOL is an IROL is made by the RC. If there is no notification, how can he make that determination? - Some coordination of SOL remediation may need to occur between entities. The corrective action I want to take may put my neighbor in extremise. The coordination is best done while keeping the RC informed.
Response: As noted above, the SAR drafting team agrees with you, but notes that this requirement is already covered by IRO-005-2 which states that : R1**.** Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following: R1.2**.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. R1.3**.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. Your comment appears to be covered by IRO-005-2. The SAR DT reviewed the proposed deletion of R10 and R11 from TOP-002-2 and made the following modifications to this posting: ▪ R10: delete due to duplication with TOP-004-0, R1; ▪ R11: shall remain.			
FRCC		☑	SOLs are a critical part operational situational awareness and of a "defense-in-depth" approach to operating reliably. It is critical for the Transmission Operator and Reliability Coordinator to be aware of areas that are stressed within his/her TOP and RC area (local and wide area view). Advance knowledge of what may initially be local or even minor issues to the BES, will allow the development of the most effective and appropriate solutions for resolving the SOLs and ensuring that they DO NOT evolve into IROLs.
NPCC CP9 RSWG HQT ISO-NE		☑	We strongly disagree with this idea. Respecting SOLs is a fundamental operational requirement. Transmission Operators must be required to closely montior their area; failing to do so may ultimately lead to cascading failures, as was witnessed on August 14, 2003. An SOLs, left unchecked, will become an IROL, which is why it is imperative that all SOLs be monitored and respected at the TOP level.
ITC Transco		☑	While SOLs may be local in nature, the mitigation of SOL violations has the potential to impact several entities of the functional model - oftentimes from different companies. Without a standard, it will be difficult to properly justify actions taken to mitigate SOL violations.

<table>
<tr><th colspan="4">Question #2</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>NYISO</td><td></td><td>☑</td><td>SOLs should be retained as part of the NERC Standards. The NYISO does not believe that SOLs are only important to local operations. SOLs also occur on BPS facilities and can cause reliability issues outside of the local utility operations, without being an IROL.</td></tr>
<tr><td colspan="4">Response: The SAR DT reviewed the proposed deletion of R10 and R11 from TOP-002-2 and made the following modifications to this posting:
R10: delete due to duplication with TOP-004-0, R1;
R11: shall remain.
TOP-002-2, R11 requires “The Transmission Operator shall …. determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.” This requirement means that the TOP must be aware of SOLs. TOP-006-0, R2 requires “Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.” This requirement addresses the comment that ‘Transmission Operators must be required to closely monitor their area’.</td></tr>
<tr><td>SOCO Transmission</td><td>☑</td><td>☑</td><td>There are many Standard requirements outside the scope of this SAR which require the RC to "monitor" potential SOLs.

As an example, IRO-003, R1 says each Reliability Coordinator shall monitor all Bulk Electric System facilities to ensure the RC is able to determine any potential System Operating Limit. If this SAR removes the standards in scope that mention SOLs but leaves IRO-003, R1, to be enforced, then ambiguity will result.

IRO-003, R2 says each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL. Again, it appears in other standards (outside the scope of this SAR) that the RC is responsible (enforceable requirement) for being aware of preliminary events that could lead to an SOL.

Additionally, IRO-002, R6 also contains such references to SOLs as well as other IRO Standards. Therefore, it appears the scope of the SAR should be broadened to include other standard requirements not contained in this SAR.</td></tr>
<tr><td>ERCOT</td><td>☑</td><td></td><td>There may be some confusion across the industry about "what are SOLs". I think there is good agreement that IROLs are applicable at the NERC Standard level, but there is</td></tr>
</table>

Question #2			
Commenter	**Yes**	**No**	**Comment**
			some identifiable reluctance within the industry to say that there is no place at all for SOLs in the NERC Standards. At the very least, there needs to be a good definition of SOL (which I believe there is), but some are concerned with the idea that IROLs are a "subset" of SOLs. Some believe that once a differentiation is made, the two should be considered separately and have separate requirements. I personally believe that IROLs are a subset of SOLs. I further believe that routine planning, operations planning, and real-time operations should be addressing all SOLs. Only during real-time operations or, more accurately, fresh post-analysis, can it be fully determined that an SOL may have sufficient consequences associated with it to qualify it as an IROL. If an IROL can be identified in advance, since by definition it relates to a single contingency, I believe a case could be made that planning and operations planning requirements have not been satisfied. In the great majority of cases, a system may be driven into an IROL through a series of unplanned events such that the system indeed may be subject to undesirable results from a "next" single contingency. However, prudent operations should dictate that no system plan to be in such a state.
MRO	☑		A System Operating Limit (SOL) does not necessarily need to be included in the standard itself, but the literature on Good Utility Practice must be issued concurrent with the implementation of the revised standard. There is a great deal of information that is very useful for the utilities implementing the standards. To aid understanding of a System Operating Limit (SOL), it would be very helpful to add some examples of a SOL in the Glossary of Terms.
Response: The SAR drafting team thanks the commenters for their input.			
FirstEnergy	☑		The reliability standards governing real-time operations should be focused on the subset of SOLs that qualify as IROLs.(reference FAC-010-1 R1.3). Blanket removal of all SOL references should be avoided and will need to be done on a case by case basis.
Response: The SAR drafting team agrees that care must be taken to consider each standard on a case to case basis, but with overall considerations as to how the standards work together to form a coherent whole.			
WECC RCCWG			While it is true that some SOLs do not have Bulk Electric System impact, such as a wave trap or customer transformer overload (local issues), others may lead to an impact on the Bulk Electic System. The group feels that if it can be shown through studies that a SOL does not have an impact on the Bulk Electic System, that particular SOL could be exempted from standards requirements. The group also questions whether a SOL without Bulk Electric System impact, but with potential local impact that would require a NERC disturbance report should be a standard requirement.
Response: Every SOL that qualifies as an IROL is covered by applicable standards such as IRO-004, -005 & -006.			

Question #2			
Commenter	**Yes**	**No**	**Comment**
Ameren	☑		
Entergy (Davis)	☑		
CenterPoint			No comment.
Entergy (Franklin)			No comment.
IRC SRC			No comment.
PSC SC			No comment.

3. **The SAR DT identified many comments submitted (See Appendix B of the SAR) on the technical content of the standards and the SAR drafting team believes that the Standards Drafting Team should consider these comments, subsequent to the approval of the SAR, in the development of Standards Revisions. Do you agree with the SAR drafting team's assessment of those comments that are being recommended for referral to the Standards Drafting Team?**

Summary Consideration: Industry consensus is to pass along all accumulated comments to the Standards Drafting Team for their consideration. (Note that the SAR DT revised the SAR to include comments recommending specific modifications to specific requirements that were provided by stakeholders during this comment period.)

Question #3			
Commenter	**Yes**	**No**	**Comment**
ATC LLC		☑	Comments submitted during the comment period should be given a greater weight in the creation of new standards. Comments submitted to other groups and different efforts are specific to those initiatives and the inclusion in this effort should be limited.
Response: The SAR DT agrees and the weight of consensus of the industry will govern the final response.			
CenterPoint		☑	CenterPoint Energy disagrees with the suggestion to remove the real and reactive capability verification testing from TOP-002-2, R13. The capability of a generator must be periodically tested to ensure that the machine will perform to its limits. Additional language should be added such that these tests are conducted on a periodic basis and not just at the requests of a BA or TOP. CenterPoint Energy believes that the requirements of TOP-002-2, R14 and R15 do belong in the Transmission Operations Standards as those variables will have a direct impact on daily operations. Any additional details or clarification can be added to other standards if necessary.
Response: The reason that this was included in the SAR is that it was considered duplicative with MOD-024 & MOD-025 by the CESDT. This point needs to be considered by the Standards Drafting Team.			
Duke Energy	☑	☑	Comments submitted should certainly be considered by the standard drafting team, but the standard drafting team should not be bound to incorporate all comments into the revised standards.
Response: The SAR DT agrees and the weight of consensus of the industry will govern the final response.			
SOCO Transmission	☑	☑	This SAR does not provide the referenced assessments the SAR drafting team has made on comments contained in Appendix B. Therefore, we can not agree or disagree with the team's assessment.

Question #3			
Commenter	**Yes**	**No**	**Comment**
Response: Thank you for your comment. Basically, the SAR DT made the decision to simply pass on the aggregated comments to the Standards Drafting Team.			
WECC RCCWG			The references, such as FERC Order 693, are so detailed that the WECC RCCWG does not believe the group can comment on the standard drafting team assessment of those comments.
Response: Thank you for your comment. Basically, the SAR DT made the decision to simply pass on the aggregated comments to the Standards Drafting Team.			
AEP	☑		Yes, we agree that the Standard Drafting Team should review and consider the merits of those comments and incorporate those comments that make sense and our complimentary to maintaining and improving reliable operations into the revised Standards.
ERCOT	☑		Each submitted comment containing technical content deserves to be given equal review by the Standard Drafting Team (SDT) once a SAR has been approved and a SDT has been selected.
IESO	☑		This seems to be a reasonable approach. However, the SDT should take these into consideration only when reviewing and revising the standards, and use its judgment on their individual merit rather than taking them as given mandates or directives.
FRCC	☑		Not sure what the question is but, Yes capturing previous analysis regarding standard content and including in this SAR and subsequent standard revisions is appropriate and effective use of previous NERC groups efforts.
NPCC CP9 RSWG HQT IRC SRC ISO-NE	☑		This may be a reasonable approach. However, the SAR DT may want to consider if they then need to pass all comments dealing specifically with the standards on to the Standards Drafting team from this process.
NYISO	☑		This may be a reasonable approach. The NYISO would recommend that all subsequent comments be provided to the Standards Drafting Team for consiration in revising the standards.
Response: Thank you for your comment.			
Ameren	☑		
Entergy (Davis)	☑		
Entergy (Franklin)	☑		
ITC Transco	☑		
Manitoba Hydro	☑		

Question #3			
Commenter	**Yes**	**No**	**Comment**
MRO	☑		
PSC SC	☑		
City of Tallahassee	☑		
FirstEnergy	☑		
Response: Thank you for your support.			

4. **Are there any standards included in the SAR that shouldn't be included?**

Summary Consideration: The SAR DT believes that there was not a consensus to delete any standards and the best way to address these comments is to pass them on to the eventual SDT and allow them and the industry (through balloting) to make the final decision.

Question #4		
Commenter	**The following standards were included in the SAR and should be removed:**	**Comment**
Duke Energy		COM-001-1, COM-002-2 and PER-001-0. See response to question 7.
Response: The weight of the industry consensus is that real-time is not restricted to just TOP standards and should include COM and PER.		
IESO		(i) We do not understand the basis to include COM-001-1, COM-002-1 and EOP-001-0 in this SAR. While there are requirements in these standards that reference TOPs, there are other standards that also reference TOPs but they are not included in this set. (ii) Some of the standards included in this SAR for revision appear to create a coordination need or potential conflicts with other SARs and draft standards: (a) The Operating Personnel Communications Protocol (OPCP) SAR is proposing to modify COM-001-1, COM-002-1, TOP-001-1, TOP-002-2, TOP-007-0 and TOP-008-1. How does this SAR Drafting Team propose to coordinate with the OPCP SAR drafting team to avoid either duplicated work effort or making changes to these standards while the draft set proposed by the other SDT are being commented or balloted? It seems like this would be difficult to accomplish and that one SAR should be delayed. (b) The Operate within Interconnected Operating Limits SDT is in the process of modifying the TOP-003, TOP-005, and TOP-006 standards as a result of changes to IRO-007-1 to IRO-011-1 standards. The coordination issues as indicated above would also need to be considered. We suggest that drafting of the standards included in

Question #4		
Commenter	**The following standards were included in the SAR and should be removed:**	**Comment**
		this SAR be put on hold until after the IRO standards are balloted and approved. (c) The Reliability-based Control SAR, which will develop the BAL-007 to BAL-011, standards is posted for comments. The coordination issues as indicated above would also need to be considered. We suggest that drafting of the standards included in this SAR be put on hold until after the BAL standards are balloted and approved. (d) Finally, the System Personnel Training drafting team is proposing to eliminate PER-001 through PER-004. This SAR would have to be updated to reflect those changes. Again this SAR should be put on hold until the PER standards are balloted.
Response: 1. The basis for inclusion of certain standards in this SAR is the comments received from various groups that clearly indicated the need to coordinate issues in different standards such as COM with real-time operations. This is being done to promote consistency and eliminate redundancy in the standards. **2.** All this SAR is trying to do is to point out possible redundancies in the standards. Your comments will be passed on to the eventual Standards Drafting Team. It will be up to them and the NERC staff to resolve any potential conflicts.		
MRO		There are several TOP standards currently under revision in other SAR's. There must be clear coordination between the Drafting Teams of the various SAR's as they are revising the Reliability Standards.
HQT		Some of the standards included in this SAR for revision appear to create a conflict with other ongoing SAR and Standard drafting activities. We are becoming more and more concerned about the parallel changes taking place.
IRC SRC		We do agree that this SAR appears to cover the right set of standards. However, it potentially conflicts with other SARs and draft standards. The Operating Personnel Communications Protocol (OPCP) SAR is proposing to modify COM-1-1, COM-002-2, TOP-001-1, TOP-002-2, TOP-007-0, TOP-008-0 standards. All of these standards are proposed to be modified in this SAR. How does this SAR Drafting

Question #4		
Commenter	**The following standards were included in the SAR and should be removed:**	**Comment**
		Team propose to coordinate with the OPCP SAR drafting team. It seems like this would be difficult to accomplish and that one SAR should be delayed. The Operate within Interconnected Operating Limits Standard Drafting team is in the process of modifying the TOP-003, TOP-005, and TOP-006 standards. Assuming these standards are eventually approved, this SAR will have to be modified to reflect the new versions of the standards. Again, this SAR should be delayed until the Operate within Interconnected Operating Limits Standards have completed the ballot process. Finally, System Personnel Training drafting team is proposing to eliminate PER-001 through PER-004. This SAR would have to be updated to reflect those changes. Again this SAR should be delayed until these standards are balloted.
ISO-NE		Some of the standards included in this SAR for revision appear to create a conflict with other ongoing SAR and Standard drafting activities. We are becoming more and more concerned about the parallel changes taking place.
NYISO		We do agree that this SAR appears to cover the right set of standards. However, it potentially conflicts with other SARs and draft standards. The Operating Personnel Communications Protocol (OPCP) SAR is proposing to modify COM-1-1, COM-002-2, TOP-001-1, TOP-002-2, TOP-007-0, TOP-008-0 standards. All of these standards are proposed to be modified in this SAR. How does this SAR Drafting Team propose to coordinate with the OPCP SAR drafting team. It seems like this would be difficult to accomplish and that one SAR should be delayed. The Operate within Interconnected Operating Limits Standard Drafting team is in the process of modifying the TOP-003, TOP-005,

Question #4		
Commenter	**The following standards were included in the SAR and should be removed:**	**Comment**
		and TOP-006 standards. Assuming these standards are eventually approved, this SAR will have to be modified to reflect the new versions of the standards. Again, this SAR should be delayed until the Operate within Interconnected Operating Limits Standards have completed the ballot process. Finally, System Personnel Training drafting team is proposing to eliminate PER-001 through PER-004. This SAR would have to be updated to reflect those changes. Again this SAR should be delayed until these standards are balloted.
NPCC CP9 RSWG		Some of the standards included in this SAR for revision appear to create a conflict with other ongoing SAR and Standard drafting activities. We are becoming more and more concerned about the parallel changes taking place.
Response: All this SAR is trying to do is to point out possible redundancies in the standards. Your comments will be passed on to the eventual Standards Drafting Team. It will be up to them and the NERC staff to resolve any potential conflicts.		
Entergy (Davis)	No.	
WECC RCCWG		None are currently identified, but some may become apparent later.
SOCO Transmission		No comment.
AEP		No comment.
Ameren		No comment.
ATC LLC		No comment.
CenterPoint		No comment.
Entergy (Franklin)		No comment.
ERCOT		No comment.
Manitoba Hydro		No comment.
PSC SC		No comment.
City of Tallahassee		No comment.
FirstEnergy		No comment.
FRCC		No comment.
ITC Transco		No comment.

5. **Are there standards that should be added to the SAR?**

Summary Consideration: The SAR will be re-posted to consider the inclusion of IRO-004, -005 & -006 in the scope.

Question #5		
Commenter	**The following standards should be added to the SAR:**	**Comment**
SOCO Transmission	IRO-002, IRO-003, IRO-005, IRO-006. However, there could be others.	
Response: The SAR DT agrees that IRO-006 should be included in the scope of this SAR for the sole topic of eliminating redundancies relating to the applicability of TOP's and BA's in the respective documents. We are uncertain about what the comments on IRO-002 & -003 mean. In reviewing this issue, it appears that IRO-004 & -005 have the same problems as IRO-006 and therefore should be included in the scope of this SAR. This will require a re-posting of the SAR for consideration by the industry.		
Entergy (Davis)	No.	
City of Tallahassee	None.	
Duke Energy	None.	
IESO	No.	
PSC SC	None.	
HQT	No.	
IRC SRC	No.	
ISO-NE	No.	
NYISO	No.	
NPCC CP9 RSWG	No.	
WECC RCCWG		None are currently identified, but some may become apparent later.

6. Do you agree that there is a reliability-related need to revise the set of standards addressed in this SAR?

Summary Consideration: The consensus is that there is a reliability-related need for this SAR.

Question #6			
Commenter	**Yes**	**No**	**Comment**
ATC LLC	☑	☑	ATC agrees that there is a reliability-related need to review and revise this set of standards, but we do not agree with the overly prescriptive changes appearing in the SAR.
Response: The SAR is a scoping document and the changes represent topics that are open to debate. The SAR DT intended to be prescriptive only in defining the scope of the work area. The SAR DT did not intend to be prescriptive in the requirements being proposed. A SAR DT does not define solutions, and this DT did not intend to define solutions. How prescriptive the standard will be is decided by the comments to the Standard DT.			
ERCOT	☑	☑	I believe that revising the set of standards for clarity and for reducing redundancy will benefit reliability by reducing confusion. There is also a common sense reason to revise them to avoid "multiple jeopardy" by exposure to the same requirement in multiple standards.
Response: Thank you, the concept that reliability requires clear unambiguous standards has support from other commenters as well as from the SAR DT.			
WECC RCCWG			The WECC RCCWG believes that some of the standard requirements need to be clarified.
Ameren	☑		It is important that the standards address those things, and only those things, that affect the reliability of the BES so that time and attention are not diverted from the most worthwhile initiatives.
Duke Energy	☑		The reliability-related need is to provide clarity and remove redundancy.
Manitoba Hydro	☑		The standards must be revised to clearly define the responsible entity for each requirement. There can't be any room for a requirement to fall through the cracks because the assignment of responsibility is not clear. Redundancy between Standards does not mitigate the risk of inadequate assignment of responsibility, but rather it may increase the likelihood that responsible entities assume that the requirements are met by others.
MRO	☑		The current versions of the standards are very voluminous and confusing. These revisions should remove the ambiguity and lead to a small set of quality reliability related requirements to be complied with.
AEP	☑		
City of Tallahassee	☑		

Question #6			
Commenter	**Yes**	**No**	**Comment**
Entergy (Davis)	☑		
Entergy (Franklin)	☑		
IESO	☑		
PSC SC	☑		
FirstEnergy	☑		
FRCC	☑		
HQT	☑		
IRC SRC	☑		
ISO-NE	☑		
ITC Transco	☑		
NYISO	☑		
NPCC CP9 RSWG	☑		
SOCO Transmission	☑		
CenterPoint			No comment.

7. **Do you agree with the scope of this SAR?**

Summary Consideration: The consensus is that the industry agrees with the stated purpose of the SAR. However, as indicated in the response for question #5, there will be a re-posting of the SAR to consider the inclusion of certain IRO standards.

Question #7			
Commenter	**Yes**	**No**	**Comment**
ATC LLC		☑	The scope of this SAR is overly prescriptive in that is has already determined a solution to the perceived deficiency. A scope needs to be detailed enough to provide a solid base for discussion and review, but not so detailed that the solution has been identified. The solution will be developed by the SDT along with industry feedback. ATC believes that this SAR is overly prescriptive and should be re-written.
Response: The SAR is a scoping document and the changes represent topics that are open to consideration. The SAR DT intended to be prescriptive only in defining the scope of the work area. A SAR DT does not define solutions, and this DT did not intend to define solutions. How prescriptive the standard will be is decided by the comments to the Standard DT.			
Duke Energy		☑	This SAR should focus only on TOP standards.
Response: The intent of the SAR was to cover unresolved real time operations issues that had been raised by FERC and other commenters. The general industry favors the wider scope.			
IESO		☑	Please see our comments under Q2 and Q4 regarding the notion of the SAR DT, and the potential conflicts with other efforts currently underway or to start soon.
HQT		☑	Please see response to Q#4.
ISO-NE		☑	Please see response to Q#4.
NPCC CP9 RSWG		☑	Please see response to Q#4.
Response: The concern about coordination with other Standard Drafting Teams is addressed by the Standards Committee and the NERC Standards Process Manager. There is also a difference between standards and requirements. There are standards that appropriately fall under more than one NERC Project; however, the requirements within that given standard should be unique to a given DT. If there are any duplicative requirements, then that is best addressed in the Standards process. To limit the scope of this SAR because another SAR may also address the same standard may in the end preclude a needed change in a specific requirement.			
SOCO Transmission		☑	The SAR needs to be broadened in scope to cover all standard requirements that contain references of the RC being responsible for SOLs and not just a subset of standards.
Response: The intent of the SAR was to cover unresolved real time operations issues that had been raised by FERC and other commenters. There is a newly constituted SAR DT to address RC issues and standards that should address your concerns. If there are additional RC standards that need to be addressed, then a new SAR can be submitted.			

Question #7			
Commenter	**Yes**	**No**	**Comment**
IRC SRC	☑	☑	This SAR should be written to apply only to TOPs. This is an opportunity to create a good quality set of standards and eliminate the existing ambiguous requirements. You should start with a clean slate.
Response: The intent of the SAR was to cover unresolved Real Time Operations issues that had been raised by FERC and other commenters**.**			
ITC Transco	☑	☑	Except for not addressing the SOL issue described above.
Response: This was addressed in the responses to question #2.			
AEP	☑		We agree with the purpose stated for this SAR. We do not agree with all of the specific changes suggested in the SAR. However, the SAR is written that the Standard Drafting Team is to consider the changes, which we do support. We believe that through a thorough debate and analysis by the Standard Drafting Team, that they too will conclude that not all the recommendations should be implemented.
Response: Thank you for your support.			
MRO	☑		The current versions of the standards are very voluminous and confusing. These revisions should remove the ambiguity and lead to a small set of quality reliability related requirements to be complied with.
Response: Thank you for your support.			
Ameren	☑		
City of Tallahassee	☑		
Entergy (Davis)	☑		
Entergy (Franklin)	☑		
ERCOT	☑		
Manitoba Hydro	☑		
PSC SC	☑		
FirstEnergy	☑		
FRCC	☑		
NYISO	☑		

8. **If you aware of any regional variances or business practices that should be developed in association with this SAR, please list them here.**

Summary Consideration: No specific comments upon the content of the SAR were submitted relative to this question.

Question #8			
Commenter	**Regional Variances**	**Business Practices**	**Comment**
MRO			We are not aware of any at this time, since we do not know the detailed changes and wording that will be in the Reliability Standards. It is imperative to include red-line versions of the revised standards to allow determination of what needs to be included in the reference documents.
Response: The SAR DT thanks MRO for its comment. The comment suggests a process that relates to the activities of the yet-to-be-established Standard Drafting Team. We agree that it is important to be able to see what specific changes are being recommended in the content of the specific standard(s) being revised, as well as any related standard(s).			
City of Tallahassee			None.
Duke Energy			None.
AEP			No comment.
Ameren			No comment.
ATC LLC			No comment.
CenterPoint			No comment.
Entergy (Davis)			No comment.
Entergy (Franklin)			No comment.
ERCOT			No comment.
IESO			No comment.
Manitoba Hydro			No comment.
PSC SC			No comment.
FirstEnergy			No comment.
FRCC			No comment.
HQT			No comment.
IRC SRC			No comment.
ISO-NE			No comment.
ITC Transco			No comment.
NYISO			No comment.
NPCC CP9 RSWG			No comment.
SOCO Transmission			No comment.
WECC RCCWG			No comment.

9. **If you have any other comments on this SAR that you haven't identified above, please provide them here.**

Summary Consideration: Accommodating changes to the SAR will be made as noted below.

Question #9	
Commenter	**Comment**
AEP	AEP encourages additional aids (i.e. whitepapers and/or teleconferences) during the drafting process to better understand the drive for removing SOLs from some of the standards.
Response: The SAR drafting team agrees that more in depth discussion of the topic can serve only to improve understanding and improvement of standard requirements and we will pass this comment on to the SDT.	
ATC LLC	Comment in the SAR: "R14 and R15 apply to the Generator Operator and as such do not belong in the TOP standards. The drafting team should look to find another place for these requirements if possible." ATC disagree with this statement. The "Purpose" statement sets the need for the standard. All entities that are needed to support the "Purpose" should be identified in the Applicability section. The label of TOP should not be the justification to exclude any entity that is not a Transmission Operator.
Response: You make a very good point. We may have overstated the problem. The SAR will be changed to read: "R14 and R15 apply to the Generator Operator and as such may be better addressed in other standards. The Standards Drafting Team should look to find another place for these requirements if possible."	
Entergy (Franklin)	We agree that the proposed changes need to be evaluated. However, it is important that the revised standards are balloted separately so that the entire set is not rejected because of an issue with one of the standards nor approved as a set with flaws or concerns in one or more of the standards.
Response: The SAR drafting team will forward your comment to the Standard Drafting Team (SDT) when it is established. One of the important decisions the SDT must make is whether to vote all changes as one package or whether some of the changes may stand alone and may be balloted individually.	
Duke Energy	If the ultimate goal is to eliminate PER-001-0 as stated on page SAR-4, it should be noted that responsibility and authority are to be provided to "operating personnel" in either a TO or a BA. However, in standard TOP-001 Requirement 1, it deals specifically with Transmission Operators, and Balancing Authority personnel are not covered under this standard. Consideration should be given to either add BAs to TOP-001 R1 or they should be given "responsibility and authority" in some other standard if PER-001 is eliminated. Also, NERC should create a companion database for the standards that links each requirement, its compliance elements and applicable entities. Such a cross-reference would facilitate standards actions dealing with groups of standards.

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Response: (1) Your point is well made. The SDT can decide whether to submit the elimination of PER-001 and to modify TOP-001 to include the BA. (2) Such a database is not within the scope of the SAR DT, however we will pass this comment on to the NERC staff.	
IESO	Specific to the proposed changes to the standards, we offer the following comments: TOP-001 R2: the SDT suggests to remove this requirement. However, R2 holds TOP responsible for taking immediate actions to alleviate operating emergencies which may be within the TOP area and not monitored by an RC, whereas R3 requires several operating entities to comply with the RC directives. The two requirements serve different purposes. R8: the SDT suggests to delete this requirement. We suggest the SDT to exercise caution and compare this requirement (restoring the system during an emergency) with other related standards to ensure that this is indeed covered elsewhere. TOP-002 R1: the SDT suggests to remove this as it is redundant with TOP-008-1 R1. Please note that TOP-002 R1 requires plans whereas TOP-008 R1 requires TOP to take action in real time. These reuqirements are different. If the SDT wants to revise TOP-002 R1 to eliminate vague requirements, we suggest that the second sentence "In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and systemequipment to implement these plans to ensure that interconnected system reliability will be maintained." be deleted. R3: the SDT suggests deleting R3 as it is redundant with TOP-004-1 R1. We disagree with this proposal. R3 requires the various operating entities to coordinate and develop operational plans; whereas TOP-004-1 requires the TOP to operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs). They are required for different time frames and purposes. R4: the SDT suggests deleting R4 as it is redundant with IRO-005-2, R9. We Disagree with this proposal. Deleting R4 would remove the obligation for BA and Top to coordinate their activities with the RC. Additionally, the two requirements serve different purposes: R4 in TOP-002 serves to ensure that normal Interconnection operation will proceed in an orderly and consistent manner; whereas R9 in IRO-005-2 serves to require the RC to develop and implement action plans to mitigate potential or

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	actual SOL, IROL, CPS, or DCS violations. R6: the SDT suggests deleting R6 as it is redundant with BAL-002-0 R4 and IRO-005-2 R9. We agree that there is redundancy with BAL-002-0 R4, but we not agree that it is redundant with IRO-005-2 R9. Deleting R6 would remove the obligation for BA and Top to coordinate their activities with the RC. Additionally, the two requirements serve different purposes: R6 in TOP-002 require TOP and BA to plan for contingencies; whereas R9 in IRO-005-2 serves to require the RC to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. R7 and R9: the SDT suggests deleting these requirements as they are redundant with BAL-007 through -011. We do not agree with the deletion of both requirements, due to the fact the standards BAL-007 to BAL-011 have failed the ballot process, and are now part of the Reliability-based Control SAR which is posted for comments. Please see our comments on Q4 (ii), above. R8, R10 and R11: the SDT suggests deleting these requirements as they are redundant with IRO-005-2 R9. We agree with this deletion provided that R4 is retained. Othewise, R10 and R11 should be retained. R18: the SDT suggests to move this to FAC-009-1. We do not agree since the purpose of FAC-009-1 is "To ensure that Facility Ratings used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or Methodologies". We veiw that R18 crosses a number of Standards so there may be a better home than FAC-009-1. TOP-003-0 R3: the SDT suggests deleting R1.3 as it is redundant with IRO-010, R3 as part of the over-all data specification effort. We believe the referenced requirement should be R4. TOP-004-0 R1: the SDT suggests deleting R1 as it is redundant with IRO-009-1, R4. We disagree with this. SAR IRO-009-1 holds the RC responsible for operated within IROL. We feel strongly that the TOP must also operate its system to respect IROL. Further, we need to defer any changes to remove or modify SOL until after the definition of Adequate Level of reliability is defined. We also provided other reasons for retaining it. Please see our comments on Q2, above.

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	R2: the SDT suggests deleting R2 as it is simply the definition of an IROL and is redundant with FAC-010-1 and FAC-011-1. We disagree with this proposal since R2 requires TOP to operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. FAC-010-1 and FAC-011-1 deal with the methodology to determine SOL and IROL. They hold different entities for doing very different things altogether. R3: We disagree with removing this requirement for the above same reason. TOP-005-1 R2: the SDT suggests deleting this requirment. We agree that R2 is not a reliability requirement, but the SDT needs to recommend a home for entities that receive data from the ISN that it must sign the NERC Confidentiality Agreement for "Electric System Reliability Data". TOP-006-1 R1: the SDT suggests deleting R1 as it is redundant with FAC-009-1, R2. We disagree with this proposal since R1 deals with real-time data such as facility status, resource availability; whereas FAC-009-1 deals with establishing ratings. R4: the SDT suggests deleting R4 as it is redundant with BAL-001 and -002 and is also addressed in IRO-010-1, R1 and R3. We disagree as R4 requires the operating entities to do things that are very different from any of BAL-001, BAL-002 and IRO-010-1. R7: the SDT considers deleting Balancing Authority as it is covered in BAL-005-0, R8 and deleting Reliability Coordinator as it is covered in BAL-008-1, R1. We do not agree with both. In the first case, the requirements for the BA in R7 is to monitor system frequency which is different than those in BAL-005-0, R8 which specify the data and metering requirements. In the second case, BAL-008 doesn't yet exist (falied ballot). TOP-008 R3: the SDT suggests deleting R3 as it is a local utility risk consideration and not a reliability issue as currently worded. We do not agree with the deletion since the requirement implies that the action taken by the TOP has interconnected system implication.
Response: TOP-001-1, R2 comment: You are correct that R2 and R3 address different concepts. However, the drafting	

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	team should have stated that the redundancy was between R1 and R2, rather than R2 and R3. R1 clearly states that the Transmission Operator shall exercise specific authority to alleviate operating emergencies. R2 is largely procedural in nature rather than stating what is to be done. This will be corrected in the re-posted SAR. TOP-001-1, R8 comment: The drafting team agrees. The SDT must include due diligence in comparing various requirements in its consideration of whether to delete R8. TOP-002-2 R1 comment: Your point is understood. The drafting team feels that the TOP has plans in place in order to take the actions required by TOP-008-1 R1. However, the requirement to have plans and the requirement to implement those plans are two different concepts. Your point about deleting the second sentence of TOP-002-2 R1 is a good recommendation. The drafting team will forward your comment to the SDT for its consideration as it makes specific revisions. TOP-002-2, R3 comment: Your statement is correct. The redundancy should reference IRO-004-1, R4, rather than TOP-004-1, R1. TOP-002-2, R7 and R9 comment: At the time the SAR was drafted, the outcome of the BAL-007—011 was not known. The SDT must take this into account as they consider whether to delete R7 and R9. TOP-002-2 R8, R10, and R11 comment: The drafting team agrees that there are complex interrelationships and redundancies throughout the standards. As the SDT considers deleting requirements, they must also watch for these relationships. TOP-002-2, R18 comment: The SAR requires that the SDT consider moving this requirement to FAC-009-1, it does not require that it do so. Part of the methodology required by FAC-009-1 is to include identifiers.
Manitoba Hydro	Specific to COM-001-1 Telecommunications: In general, we support the proposed revisions to this standard with the following exceptions. Periodicity and type of testing should not be defined explicitly in the standard. The onus must be placed on each organizaton to determine the periodicity and testing requirements as necessary to meet expected performance criteria. Such requirements would require regular review and adjustment to address changing conditions. Appendix B - FERC Order 693: We are concerned that the proposed expansion of the Standard to

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	included Generator Operators and Distribution Providers is unachievable within a reasonable period of time relative to ongoing efforts to comply with current standards, i.e., too much too fast. Specific to TOP-005 Operational Reliability Information If the proposed changes are adopted, only one requirement R3 remains in this standard. This requirement involves Balancing Authorities (BAs)and Transmission Operators (TOs) supplying on-line information to associated BAs and TOs for reliability assessments and coordinated operations. This same information is also transmitted to the Reliability Coordinators (RCs)via requirement R1. (which is now to be transferred to and covered by IRO-010-1). If the RCs are receiving all the required reliability data anyway, why can't all concerned BAs and TOs get this same data from the RCs instead of directly from the concerned utility? Won't all BAs and TOs be required to send reliability data the closest RCs, even if they are not already a direct or associate member of any established RC? Keeping TOP-005 only for R3 opens the door to potential reliability analysis and data being developed and transmitted between interconnected BAs and TOs that is NOT also transmitted to RCs. It may be better to make TOP-005 R3. part of another standard (such as IRO-010) to ensure RCs are properly informed, and then eliminate TOP-005 altogether.
Response: COM-001-1 comment: Your comment may apply if there is valid reason for different performance criteria in different organizations. The SAR drafting team will forward your comment to the Standard Drafting Team (SDT) once the SAR is approved, since it deals with a specific treatment of a requirement that the SAR directs the SDT to consider for revision. Appendix B – FERC Order 693 comment: Your concern is noted. However, the drafting teams must address directives of FERC in the revision of standards. You are encouraged to continue your review and to make appropriate comments of each draft of the standard that is posted. TOP-005-1 comments: The purview of the RC may differ from that of the BA and TOP. The RC must have a wider view of the system for which it is responsible and may not analyze down to the "local" level of each BA and TOP system. However, your concepts are interesting and should be part of the activity of the Standards Drafting Team (SDT) when the team is considering the revisions as directed by the SAR.	
MRO	As the standards are revised, it is necessary to insure there is, at a minumim, one measurement for each requirement. If a measure can not be determined for a requirement, the requirement should be rewritten or deleted.
Response: Some measurements may realistically relate to more than one requirement. However, each requirement should	

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have a measurement which does apply to it. One of the aspects of a good standard requirement is for it to be clear as to what is to be done, by whom, and to what expected result.	
FRCC	The revisions being made under this SAR should be well coordinated with the revisions being made under the Reliability Coordination SAR (Project 2006-06). Both SARs are seeking to revise COM-001 and COM-002. It is also critical that language proposed in the revisions of both projects be well coordinated because of the interrelated nature of the applicable standards.
Response: Each SDT should review related actions of other projects to the extent that the timing allows them to do so. In most cases, each project is revised from a different perspective and conflicting revisions should not occur. This need to coordinate between drafting teams is recognized and the drafting team guidelines caution the drafting teams to keep this in perspective throughout their work.	
IRC SRC	The SAR proposes to add the language "without delay" to a number of requirements. We are concerned that this wording could be interpreted in a standard to require the need for immediate control action. We propose that the standard drafting team should clarify that the "without delay" language does not require immediate control action but requires the applicable entity to begin evaluations necessary to take control actions. These evaluations may include but are not limited to verifying the limit, measurement, or performing a on-line power flow study.
NYISO	The SAR proposes to add the language "without delay" to a number of requirements. We are concerned that this wording could be interpreted in a standard to require the need for immediate control action. We propose that the standard drafting team should clarify that the "without delay" language does not require immediate control action but requires the applicable entity to begin evaluations necessary to take control actions. These evaluations may include but are not limited to verifying the limit, measurement, or performing a on-line power flow study.
Response: The SAR drafting team agrees with your comment. Actions include recognition, investigation, and verification prior to actual control actions. We will pass this comment along to the eventual SDT.	
SOCO Transmission	It is recommended that the drafting team members review all alleged duplications closely to be sure that the true meaning of the duplicated statement is the same as the orginal statement before being deleted. There could be instances where the words are the same but the meaning behind the duplication could be different.
Response: Thank you for your suggestion. The guidelines for the SDT require that they pay close attention to background and content of each requirement considered for revision or retirement.	
WECC RCCWG	The WECC RCCWG suggests differentiating TOP directives from Reliability Coordinator directives. This may be done with specific language. It should be clear to the entity receiving a directive who issued that directive. It may be beneficial to have a NERC definition for a "Reliability Coordinator Directive" and a "Transmission Operator Directive".
Response: The SAR drafting team encourages you to continue to review drafts of standard revisions that the SDT will post	

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Commenter	**Comment**
for comment. You may suggest specific changes to specific standard requirements at that time. If there is not an existing standard for which this comment appropriately relates, you may submit a SAR to request the establishment of such requirements.	
City of Tallahassee	None.
Ameren	No comment.
CenterPoint	No comment.
Entergy (Davis)	No comment.
ERCOT	No comment.
PSC SC	No comment.
FirstEnergy	No comment.
HQT	No comment.

Standard Authorization Request Form

Title of Proposed Standard	Real Time Operations (Project 2007-03)
Request Date	March 15, 2007
Revised Date	August 6, 2007

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Jim Case	☐	New Standard
Primary Contact	Jim Case	X	Revision to existing Standard
Telephone	870.541.3908	X	Withdrawal of existing Standard
E-mail	jcase@entergy.com	☐	Urgent Action

Purpose

Applicable Standards:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- IRO-004-1 Reliability Coordination – Operations Planning
- IRO-005-2 Reliability Coordination – Current Day Operations
- IRO-006-3 Reliability Coordination – Transmission Loading Relief
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The purpose of revising these standards is to:

1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards.
2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B.
3. Consider other general improvements as described in Appendix A.
4. This satisfies the ANSI procedure requirement for five-year review of the standards.

Industry Need

The industry needs clearer, unambiguous and enforceable standards in order to effectively operate the Bulk Electric System.

Detailed Description

The drafting team should address the following general changes:

- Adjust measures to match any changes to requirements.
- Add measures as needed to complete the alignment of measures with requirements.
- Address issues outlined in Appendix A.
- Review the industry comments provided during the Version 0 process, CESDT Project, RRSWG efforts, VRF work, etc., as outlined in Appendix B.
- Address the comments from FERC Order 693 as outlined in Appendix B.

In addition, the drafting team should consider the following specific changes in the TOP and COM standards:

- TOP-001-1:
  - Removal of R2 due to redundancy with R1. R2 largely describes an ill-defined procedure which should not be in a standard.
  - Adding the wording ‘without delay’ after the phrase ‘shall comply’ in the first sentence of R3.
  - Adding the wording ‘without delay’ in place of ‘immediately’ in all requirements where appropriate.
  - Eliminating R5 in light of possible redundancy with IROL standards.
  - Deleting the phrase ‘all available’ from R6.
  - Replacing ‘burden’ with ‘adversely impact system reliability of’ in R7.
  - Replacing ‘generator outage’ with ‘generation facility’ in R7.1.
  - Replacing ‘at the earliest possible time’ with ‘without delay’ in R7.3.
  - Deleting R8 as it is redundant with IROL, BAL, VAR and EOP standards.
- TOP-002-2:
  - Deleting R1 as it is redundant with TOP-008-1 R1.
  - Deleting R2 as it is simply good utility practice and not really a reliability standard.
  - Deleting R3 as it is redundant with IRO-004-1, R4.
  - Deleting R4 as it is redundant with IRO-005-2, R9.
  - Deleting R5 as it is simply good utility practice and not really a reliability standard.
  - Deleting R6 as it is redundant with BAL- 002-0, R4 and IRO-005-2, R9.
  - Deleting R7 and R9 as they are redundant with BAL-007 through -011.
  - Deleting R8 as it is an unmeasurable requirement.
  - Deleting R10 as it is redundant with TOP-004-0, R1.
  -
  - Deleting R12 as it is redundant with FAC-010 and -011.
  - Removing references to the Balancing Authority and real power output from R13 as they are contractual issues and as such can not be incorporated in a standard. The remaining language should be clarified.
  - R14 and R15 apply to the Generator Operator and as such may be better addressed in other standards. The drafting team should look to find another place for these requirements if possible.
  - Deleting R16.2 as it is redundant with FAC-009-1.
  - Deleting R17 as it is no longer needed if the above mentioned changes are made.

  - R18 should be moved to FAC-009-1.
  - Deleting R19 as it can not be measured.
- TOP-003-0:
  - The drafting team should review the 50 MW requirement in R1.1 to determine the size where a generator can have an adverse impact on the Bulk Electric System. See FAC-008-3.
  - Delete Reliability Coordinator when IRO-010-1 is placed in service.
  - Delete R1.3 as it is redundant with IRO-010, R3 as part of the over-all data specification effort.)
  - Re-wording R2 to require general coordination of all facilities that affect Bulk Electric System reliability.
  - Delete R4 in deference to the RC Project.
- TOP-004-1:
  - Delete the reference to SOL in R1.
  - Deleting R2 as it is simply the definition of an IROL and is redundant with FAC-010-1 and FAC-011-1...
  - Deleting R3 as it is redundant with FAC-010-1 and FAC-011-1.
  - Re-word R6 for clarity.
- TOP-005-1:
  - Deleting R1 as it is redundant with IRO-010-1.
  - Deleting R1.1 as it is redundant with IRO-010-1.
  - Deleting R2 as it is not a reliability concern.
  - Re-wording R3 to provide more clarity and simplicity.
  - Deleting R4 as it is redundant with INT-001-2, R1.
  - When IRO-010-1 becomes effective, Attachment 1 should be translated into a technical specification. It is only a partial list of required data.
- TOP-006-1:
  - Deleting R1 as it is redundant with FAC-009-1, R2.
  - Deleting the Balancing Authority from R2 as the list of items does not apply. Consider deleting the Reliability Coordinator from R2 as it is redundant with IRO-007-1, R1.
  - Moving R3 to PRC-001.
  - Deleting R4 as it is redundant with BAL-001 and -002 and is also addressed in IRO-010-1, R1 and R3.
  - Deleting R5 as (1) it is good utility practice and not a true reliability requirement or (2) provide clarification on the utilization of alarm processing and to provide definition of important deviations or (3) move the requirement to ORG-004-0.
  - Deleting R6 as it is redundant with BAL-005-0, R17.
  - R7: Consider deleting Balancing Authority as it is covered in BAL-005-0, R8. Consider deleting Reliability Coordinator as it is covered in BAL-008-1, R1.
- TOP-007-0:
  - Rewording R2 to say that the Transmission Operator shall act ‘without delay’ to return the transmission system to within IROL as soon as possible but not longer than the IROL T_v. The 30 minute time frame should be deleted as it is redundant with IRO-009-1, R2.
  - Delete R4 in deference to the RC Project.
- TOP-008-0:
  - Deleting R1 as it is redundant with TOP-007-0, R3.
  - R2: Suggested wording as follows:
    - R2a: For each IROL or SOL that is identified in advance of Real-time, the TOP shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take to prevent exceeding those IROLs or SOLs or to mitigate actual violations *(Violation Risk Factor: Medium) (Mitigation Time Horizon: Operations*

    - *Planning)*
    - R2b. If the involved TOPs cannot agree on a solution or if there is a difference in derived operating limits (IROLs or SOLs), the more conservative solution or limit shall be utilized.
  - Deleting R3 as it is a local utility risk consideration and not a reliability issue as currently worded.
  - Re-wording R4 for clarity.
- COM-001-1:
  - Re-word R1 to provide clarity to terms such as ‘adequate’ and ‘reliable’. The term ‘telecommunication facilities’ needs to be explicitly defined or re-worded to provide clarity.
  - Define ‘internally’ in R1.1.
  - Delete R1.4 on the basis that it is covered in the new definitions of ‘adequate’ and ‘reliable’. The current phrasing could be interpreted that specific telecommunication devices must be redundant. We believe that this was not the original intent of this requirement. The intent should be to provide redundant telecommunication capability between reliability entities.
  - In R2, periodicity and type of testing, ‘vital’ and ‘special attention’ should be defined.
  - Re-word R3 to make clear that each reliability entity shall notify reliability entities to which you have a communication path prior to changes in telecommunication facilities that would affect them and to resolve any coordination issues.
  - Delete R6 as it is simply an ERO procedural issue. It is assumed that if it belongs in standards that it would be in CIP as opposed to COM. This would then cause the deletion of Attachment 1 and would remove NERC Net User Organization as an applicable entity.
- COM-002-2:
  - Delete the first sentence of R1 as it is redundant with COM-001-1 if the Generator Operator is added as an applicable entity in COM-001-1. Delete the second sentence as it is redundant with PER-003-0, R3.
  - Re-word R1.1 to provide clarity as to the definition of applicable areas. Delete the requirement for firm load shedding as it is not a reliability issue.
  - Re-word R2 to provide clarity for the terminology ‘clear, concise and definitive’. The use of scripts is a possible solution.

Remove applicability and all references to TOP in PER-001-0 due to redundancy with TOP-001-1, R1 with the ultimate goal to eliminate PER-001-0.

There is an industry need to retain good utility practice information that may be deleted from standards requirements. Any requirements so deleted should be considered for movement into appropriate guides or reference documents.

Note that Appendix B is an informative attachment that contains material that should be addressed in the standards revision process. It should not be considered to contain mandatory changes to the standard.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
X	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
X	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
X	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
BAL-001	Real Power Balancing Control Performance
BAL-002	Disturbance Control Performance
BAL-005	Automatic Generation Control
BAL-007	Balance of Resources and Demand
BAL-008	Frequency and Area Control Error
BAL-009	Actions to Return Frequency to within FTL
BAL-010	Frequency Bias Settings
BAL-011	Frequency Limits
FAC-008	Facility Ratings Methodology
FAC-009	Establish and Communicate Facility Ratings
FAC-010	System Operating Limits Methodology for the Planning Horizon
FAC-011	System Operating Limits Methodology for the Operations Horizon
INT-002	Interchange Transaction Tag Communication and Reliability Assessment
IRO-004	Reliability Coordination – Operations Planning
IRO-005	Reliability Coordination – Current Day Operations
IRO-006	Reliability Coordination – Transmission Loading Relief
IRO-007	Monitoring the Reliability Coordinator Wide Area
IRO-009	Reliability Coordinator Actions to Operate Within IROLs
IRO-010	Reliability Coordinator Data Specification and Collection
ORG-004	Transmission Operator Certification – Data Acquisition and Monitoring
PER-003	Operating Personnel Credentials
PRC-001	System Protection Coordination

Related SARs

SAR ID	Explanation
Reliability Coordination: Project 2006-06	There are parallels between this SAR for Transmission Operators and the SAR for Reliability Coordinators that must be taken into account in the development of the eventual standards.

Regional Differences

Region	**Explanation**
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A

Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Electric System, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the Bulk Electric System. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

Time Horizon

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. (‘Violation severity levels’ replaces the existing ‘levels of non-compliance.’) The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, ‘Regional Reliability Organization’ with ‘Compliance Enforcement Authority’

Fill-in-the-blank Requirements

Do not include any ‘fill-in-the-blank’ requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, ‘Associated Documents’.

Appendix B: List of Comments

The following items are comments received from various sources that shall be considered by the SDT.

COM-001-1

CESDT: (Compliance Elements Standards Drafting Team)

- R1: clarify 'adequate', 'reliable' and 'internally'.
- The statement 'Where applicable, these facilities shall be redundant and diversely routed' should be a guide and not a requirement. It would also appear that this is duplicated in COM-002-2, R1.
- R2: clarify the term ' Special attention'.
- R3: clarify 'shall provide a means' and the 'ability to investigate'.

VRFSDT: (Violation Risk Factors Standards Drafting Team)

- R6: administrative.

Version 0 Industry Comments:

- Gerald Reahlt, Manitoba: There may be redundancy here with Policy 5A Requirement 1.
- Robert Snow: R1 **-** In section R1, for all but the smallest areas, redundancy and diversely routed telecommunications is required.
- Guy Zito, NPCC: R1 thru R5 **-** Add "Transmission Owners, Generator Owners, Generator Operators and Load Serving Entities" to the list of FM entities this applies to.
- Ralph Rufrano, NYPA: NPCC's participating members recommend changing R1 to;
  Each Reliability Authority, Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator and Load Serving Entity shall provide adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability. Where applicable, these facilities shall be redundant and diversely routed. -and changing R2 – R5 from "Each Reliability Authority, Transmission Operator, and Balancing Authority shall" To "Each Reliability Authority, Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator and Load Serving Entity shall" -Remove R6 and attachment 029-1 should be removed. Those procedures apply to NERCnet users, which is a small subset of community that R1 – R5 apply to. Also, these procedures are the steps for obtaining and using NERCnet. Those procedures should not be part of a Reliability Standard.

FERC Order 693:

- Expand the applicability of the standard to include Generator Operators and Distribution Providers and include requirements for their telecommunication facilities (or as an alternative to applying this Reliability Standard to Generator Operators and Distribution Providers, develop a new Reliability Standard that will address the requirements for telecommunication facilities applicable to Generator Operators and Distribution Providers).
- Identify specific requirements for telecommunications facilities for use in normal and emergency conditions that reflect the roles of the applicable entities and their impact on Reliable Operation
- Include adequate flexibility for compliance with the Reliability Standard, adoption of new technologies and cost-effective solutions

COM-002-2

CESDT:

- R1, part 2: clarify 'Such communication shall be staffed and available for addressing a real-time emergency condition'.
- R2: clarify 'clear, concise and definitive manner'. Define 'directive'.

V0 Industry Comments:

- Mike Kormos, PJM: In a Market environment voice communication with generators is not necessarily required.
- FRCC: R1 - Reliability Authority should be included in this requirement.
- Ray Morella, First Energy: R2 - All groups active in the industry should be required to report sabotage incidents and security breaches.
- Guy Zito, NPCC: R4 - Even though this is a direct translation of the existing Policy, NPCC requests a clarification of the repeat back requirements, specifically are they for emergency, abnormal, normal, all of the above, provide specific examples.

FERC Order 693:

- Expand the applicability to include distribution providers as applicable entities.
- Include a new requirement for the Reliability Coordinator to assess and approve actions that have impacts beyond the area view of a Transmission Operator or Balancing Authority.
- Require tightened communications protocols, especially for communications during alerts and emergencies.
  - Alternatively, develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26 in the manner described above.
- Include APPA's suggestions to complete the Measures and Levels of Non-Compliance.

PER-001-0

V0 Industry Comments:

- Southern Company: Compliance Monitoring Process - The Data Retention requirement for this standard should be 1 year. The probability exists that over time, the job description and perhaps other documentation will be modified. There should not be a requirement to keep past versions of authorizing documents for an indefinite period of time.
- Bill Squib, ECAR: In the Compliance Monitoring Process… if the Reset Period is One Calendar Year, then why is the Data Retention Permanent. In addition, what kind of data is considered for Data Retention. Surely a 10-year old Job Description that has been updated several times does not need to be retained permanently.

TOP-001-1

CESDT:

- R8: essentially duplicated in other areas; clarify reactive power balance.

V0 Industry Comments:

- Michael Moltane, ECAR: (1) Need good, clear definition of "Reliability Emergency" for this to work. Otherwise we will get into the endless and age-old discussion of "what is an emergency?" (2) R1: Recommend adding wording to the sentence "clear decision making authority" that such authority should be documented and incorporated into Operating Procedures so that there will not be any confusion in real time emergencies as to who is responsible for what, and to whom.
- Roman Carter, Southern Company: (1) This req. states "The RA, BA, and TO shall have the responsibility…". The original language in Policy 5 for this requirement uses Operating Authority and this includes entities such as the GO, TO, and BA but not the Reliability Coordinator. Throughout this V-0 Standard the RA is subsituted for the RC even within this requirement. Since the original policy says RCs are excluded, this poses a conflict for this requirement. This is also in Req's 2, 4, 5. (2) There are times when a Generator Operator must act quickly and may not have time to notify the Transmission Operator. There needs to be an exception here (like that listed in 7C for the RA and TOP) for emergency situations that allows follow up notification by the GO.
- Southern Company: R4 and R6 - Should specify that the local RA will handle all communications with other potentially impacted Reliability Coordinators. As written (Reliability Authority or …), these requirements could lead to multiple notifications and potential confusion as to exactly what action is going to happen or has taken place. In general, all communications with adjacent Reliability Authorities should be through the local Reliability Coordinator. (Note that R4 may intend that RA contact other RAs, etc., but this is not clear and could easily be misinterpreted.)
- Peter Henderson, IMO: In the sentence: "Under these circumstances the Transmission Operator or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive …" The use of "or" is confusing and may create ambiguity. The specific role of entity responsible for 'providing' and 'receiving' information needs to be clarified. Should this be combined responsibility applicable to all or for any? **For the purposes of effective implementation/enforcement of these standards, we recommended that the associated measures, compliance monitoring process and levels of non compliance should also be (a) simultaneously mapped/specified where these exist already and (b) specifed/addressed in the very near future, where these do not exist today for consistency. **This comment also applies to Standards 19, 21, 26, 34 and 35.

FERC Order 693:

- Include Measures and Levels of Non-Compliance for Requirement R8.
- Consider adding other Measures and Levels of Non-Compliance in the Reliability Standard.
- Consider revising Requirements R7.2 and R7.3 to provide that the transmission operator may notify the Reliability Coordinator or the Balancing Authority that it is removing facilities from service as suggested by Santa Clara.

TOP-002-2

CESDT:

- R1, part2: clarify 'Transmission Operator shall be responsible for using available personnel and system equipment'.
- R2: too vague
- R3: too vague; clarify 'coordinate'.
- R4: too vague; clarify 'coordinate'.
- R12: duplicated in FAC-013.

- R13: duplicated in MOD-024 & MOD-025.
- R17: incorrectly written.
- R19: too vague; clarify 'accuracy'; determine timeliness of model.

Regional Reliability Standards Working Group (RRSWG):

- R6: remove 'in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements'.
- R12: remove 'in accordance with filed tariffs and/or regional Total transfer Capability and Available Transfer capability calculation processes'.

V0 Industry Comments:

- Alan Johnson, Mirant: Concerned that the translation from Control Area to BA or TOP creates a new requirement for the GOP. The proposed language allows the possibility of the GOP having to perform tests at the request of both the BA and TOP. The GOP should only be required to perform 2 seasonal capability tests per year (winter and summer) within pre-defined parameters.
- Southern Company: General - Hierarchical structure seems to be implied, but not explicitly defined in the translation of Control Area and Reliability Coordinator language to functional model language. May want to consider writing requirements such that all Balancing Authorities and Transmission Operators within a given Reliability Authority's area should coordinate their operations planning, etc.
- PG&E: R3, R4, R5 - The parentheticals "where confidentiality agreements allow" imply that confidentiality agreements trump coordination of operational plans needed to assure system reliability. They should be eliminated. Reliability Authorities would then be responsible for coordination between each other, etc. Seems confusing and/or difficult to follow as written.
- Roman Carter, Southern Company: (1) 4, 5 - Requirement says LSE, TSP, and GO coordinate with BA (where confidentiality agreements allow). Under the F.M., the BA can delegate certain tasks that prevent the BA from meeting the Conf. Agreement in order for the BA to meet the obligations of the BA. Version-0 Standard should recognize this ability. (2) Requirement states without intentional delay. How is this enforceable? The burden of proof is with the enforcement organization.
- Ray Morella, First Energy: R7 - Need to explicitly and precisely define what N-1 contingency means.
- Raj Rana, AEP: R18 - R18 only needs to state that the BALANCING AUTHORITIES shall, without any intentional time delay, communicate the information described in the requirement R15 above to their RELIABILITY AUTHORITY, or add such statement to R15. R17 already requires notification to the RA, and these were the activities that Policy today requires notification to the RA, as referenced in Policy 6A R6.1 - 6.5.
- Peter Lebro, National Grid: R3, R4, R5, R12, R17: Confidentiality of information should not be a factor when it comes to reliability – this needs to be addressed otherwise Companies may hide behind the confidentiality clause and not provide the data necessary to conduct operational reliability assessments and coordinate reliable operations.

FERC Order 693:

- Delete references to confidentiality agreements in Requirements R3 and R4, but address the issue separately to ensure that necessary protections are in place related to confidential information.
- Require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.
- Require next day analysis of minimum voltages at nuclear power plants auxiliary power busses.
- Require simulation contingencies to match what will actually happen in the field.

TOP-003-0

VRF:

- R4: poorly written.

V0:

- Peter Lebro, National Grid: Standard 16:R1, Standard 37:R4: In the standards it states outage data (generation and transmission) is only required to be submitted by noon of the day ahead, the emphasis should be on submitting the data as soon as it is known but no later that noon day ahead.
- Anita Lee, AESO: CMP - Third paragraph - The RA should "direct" the cancellation of an outage, not "request".
- Robert Snow: Outage information is needed by neighboring reliability authorities much sooner than one day pror to the outage.

FERC Order 693:

- Include a new requirement to communicate longer term outages well in advance to ensure reliability and accuracy of ATC calculations.
- Make any facility below the voltage thresholds that, in the opinion of the Transmission Operator, Balancing Authority, or Reliability Coordinator, will have a direct impact on the operation of the Bulk Power System, subject to Requirement R1 for planned outage coordination.
- Incorporate an appropriate lead time for planned outages.

TOP-004-1

CESDT:

- R1: TOP cannot always operate within IROL.
- R2: need to be able to measure ‘planning to prevent such an occurrence’.
- R3: same comments as R2; clarify ‘when practical’.
- R5: clarify ‘every effort to remain connected’ and ‘imminent danger’.

V0:

- Brandian, ISO-NE: In the existing policy the overall role of monitoring of SOL or IROL was assigned to a Control Area. In the applicable version 0 standards a clarification on the role and relationship between Reliability Authority and Transmission Operator should be made with regards to the monitoring of SOL & IROL.
- Guy Zito, NPCC: (1) These Standards must clearly identify, define and provide examples of what a SOL and IROL are. The reason for this is that this is not consistently interpreted by industry. (2) (Also in R5) This needs to be clarified whether these requirements have to be fulfilled by both presently worded RA (i.e. new proposed terminology RC) and TO - “individually or jointly”. It is not clear that who would be overall monitor. A more clear role needs to be identified in this standard. Also Reliability entity should be termed as ‘RC’.
- Robert Snow: Transmission Security during operation should conform to the applicable portions of Table 1 in the planning standards.

- Vinod Kotecha, Con Edison: There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. The RC has been designated as being responsible for maintaining the interconnection within IROLs, however debate on how these should be calculated continues.
- Tracy Edwards, BPA: R5 indicates that every effort shall be made to remain connected to the Interconnection. However the second sentence of the requirement implies that it may be acceptable to disconnect from the Interconnection if there is imminent danger of violating an IROL or SOL. There can be other conditions other than violating IROL's or SOL's that place the system at great risk. In fact, violating an IROL or SOL in itself does not necessary mean the system is at imminent risk. Therefore, change the second sentence of R5 to read as follows: The Reliability Authority or Transmission Operator may take such actions as disconnecting from the Interconnection, as it deems necessary, to protect its Area.
- Roman Carter, Southern Company: It is not practical to say the RA and the TOP operate, when practical, to protect against instability, separation, or cascading outages. Recommend removing "when practical" because when is it ever practical to allow cascading outages.

<u>FERC Order 693:</u>

- Modify Requirement R4 to state that the system should be restored to respect proven limits as soon as possible, taking no more than 30 minutes.
- Define high risk conditions under which the system must be operated to respect multiple outages in Requirement R3.

<u>TOP-005-1</u>

<u>V0:</u>

- Brandian, ISO-NE: Applicability - Add Generator Owners and Load Serving Entities. Extend R5 to include these Functional Model entities.
- Ed Riley, CAISO: R1 - Current policy is for data to be updated every 10 minutes, and is in Standard 15. This rate is too slow and should be increased (every 4-10 seconds) when possible. This should be addressed in Version 1.
- Robert Snow: In Attachment 1, the generator data should include status of voltage control and power system stabilizer facilities.
- Tracy Edwards, BPA: Attachment 015-1: Need a time frame for this data, it is not measurable as it reads now.
- Peter Lebro, National Grid: National Grid USA would like to make the following recommendations to be considered when drafting the next draft of Version 0. Standard 15: There should be a requirement on generators to provide the necessary data as there is a requirement on the PSE’s (R6), a paragraph R7 should be inserted which reads ‘Generation Operators shall provide information requested by their host Balancing Authority and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.’

<u>FERC Order 693:</u>

- Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.
- Delete references to confidentiality agreements, but address the issue separately to ensure that necessary protections are in place related to confidential information.

TOP-006-1

CESDT:

- R3: quantify relay information that is required and the scope of the relays to be included; clarify what constitutes 'appropriate technical information'.
- R6: clarify 'measure requirement'

VRF:

- R1, 1.1 & 1.2: may need 'available in emergency situation'
- R3: define 'appropriate'.
- R4: what information is required and what is a load pattern?

V0:

- Guy Zito, NPCC: Associated Measure, Compliance Monitoring Process and Levels of Non Compliance are missing and needs to be defined in this standard simultaneously.
- Michael Moltane, ECAR: R1.1: Should clarify that the the Gen Operator needs to provide "normal and emergency capability for use", as opposed to current wording of just ".all generation resources available for use" (i.e., stretch capability, maximum run time for emergency capability, etc.). R7: Indicates that entities shall "monitor system frequency"……recommend adding wording to indicate frequency shall monitor system frequency at multiple points on their system.
- Alan Boesch, NPPD: R4 - In the Functional Model load forecasts are developed by the Load Serving Entity and provided to the Balancing Authority. The BA sends the agregated information to the RA. The TOP is not involved in this process. Please change the requirement to match the functional model.
- Various entities: R4 - Load forecasting is the starting point for planning capacity for obligations and thus, deemed to be required for reliability.

FERC Order 693:

- Include a new requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk Power System.
- Clarify the meaning of "appropriate technical information" concerning protective relays.

TOP-007-0

V0:

- Ed Riley, CAISO: Measures - 2nd paragraph should be changed to read "…within IROL or SOL…" The CAISO believes that suggesting that the determination of an SOL becoming an IROL after the fact is inappropriate.
- Eric Grant, Progress: R1-R5 - In general, unless better bounds/criteria are set for the determination of IROLs, this standard will not be enforceable or auditable.
- Phil Creech, Progress: "Applicability" for this standard should include "Reliability Authorities".
- Various entities: R5 - This should be considered as a compliance monitoring or administrative procedure rather than a standard.

- Martin Huang, BC Transmission: R1 and M1 both requires the Reliability Coordinate be informed of any IROL or SOL violation but the level of non-compliance only applies when the limit is exceeded more than 30 minutes and none for failure to report the violation.
- Tracy Edwards, BPA: (1) Compliance Monitoring Process: (bullets following the first paragraph) 2) … Is vague and not measureable 3) … Would not necessarily make it an IROL. 4) … Would not nessarly make it an IROL. 5) … Is vague and there is no unacceptable loss of load definition for NERC that is measurable. (2) Compliance Monitoring Process: (first paragraph, second sentence) If this sentence were true the violation would have been an IROL to begin with. Give an example of this scenario. (3) Give an example of how you would show evidence something was evaluated. This does not seem like a possible measure. Also the RC may not have needed to give any additional direction and would therefore not have any evidence as required by the measure.
- Linda Campbell, FRCC: Standard 008, M1-M3. What kind of evidence is anticipated? The word evidence can be very subjective and broad. Also the RA should be removed from these measures.

FERC Order 693:

- Consider comments from APPA, FirstEnergy and SoCal Edison that the Reliability Standards would benefit from the elimination of overlapping matters in TOP-007-0 and TOP-008-1.
- Consider comments from the NRC that raised some significant issues regarding nuclear power plants voltage requirements.

TOP-008-0

CESDT:

- R2: clarify ‘prevent the likelihood’.
- R4, part 2: clarify ‘in all operating timeframes’.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	Real Time Operations (Project 2007-03)
Request Date	March 15, 2007
Revised Date	August 6, 2007

SAR Requestor Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Jim Case	☐	New Standard
Primary Contact	Jim Case	X	Revision to existing Standard
Telephone	870.541.3908	X	Withdrawal of existing Standard
E-mail	jcase@entergy.com	☐	Urgent Action

Purpose
Applicable Standards: ▪ COM-001-1 Telecommunications ▪ COM-002-2 Communications and Coordination ▪ IRO-004-1 Reliability Coordination – Operations Planning ▪ IRO-005-2 Reliability Coordination – Current Day Operations ▪ IRO-006-3 Reliability Coordination – Transmission Loading Relief ▪ TOP-001-1 Reliability Responsibilities and Authorities ▪ TOP-002-2 Normal Operations Planning ▪ TOP-003-0 Planned Outage Coordination ▪ TOP-004-1 Transmission Operations ▪ TOP-005-1 Operational Reliability Information ▪ TOP-006-1 Monitoring System Conditions ▪ TOP-007-0 Reporting Sol and IROL Violations ▪ TOP-008-0 Response to Transmission Violations ▪ PER-001-0 Operating Personnel Responsibility and Authority The purpose of revising these standards is to: 1. Clarify requirements for real-time operations of the Bulk Electric System in the cited standards. 2. Consider stakeholder comments received during the initial development of the standards and other comments received from ERO regulatory authorities as noted in Appendix B. 3. Consider other general improvements as described in Appendix A. 4. This satisfies the ANSI procedure requirement for five-year review of the standards.

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Industry Need

The industry needs clearer, unambiguous and enforceable standards in order to effectively operate the Bulk Electric System.

Detailed Description

The drafting team should address the following general changes:

- Adjust measures to match any changes to requirements.
- Add measures as needed to complete the alignment of measures with requirements.
- Address issues outlined in Appendix A.
- Review the industry comments provided during the Version 0 process, CESDT Project, RRSWG efforts, VRF work, etc., as outlined in Appendix B.
- Address the comments from FERC Order 693 as outlined in Appendix B.

In addition, the drafting team should consider the following specific changes in the TOP and COM standards:

- TOP-001-1:
  - Removal of R2 due to redundancy with R1. R2 largely describes an ill-defined procedure which should not be in a standard.
  - Adding the wording 'without delay' after the phrase 'shall comply' in the first sentence of R3.
  - Adding the wording 'without delay' in place of 'immediately' in all requirements where appropriate.
  - Eliminating R5 in light of possible redundancy with IROL standards.
  - Deleting the phrase 'all available' from R6.
  - Replacing 'burden' with 'adversely impact system reliability of' in R7.
  - Replacing 'generator outage' with 'generation facility' in R7.1.
  - Replacing 'at the earliest possible time' with 'without delay' in R7.3.
  - Deleting R8 as it is redundant with IROL, BAL, VAR and EOP standards.
- TOP-002-2:
  - Deleting R1 as it is redundant with TOP-008-1 R1.
  - Deleting R2 as it is simply good utility practice and not really a reliability standard.
  - Deleting R3 as it is redundant with IRO-004-1, R4.
  - Deleting R4 as it is redundant with IRO-005-2, R9.
  - Deleting R5 as it is simply good utility practice and not really a reliability standard.
  - Deleting R6 as it is redundant with BAL- 002-0, R4 and IRO-005-2, R9.
  - Deleting R7 and R9 as they are redundant with BAL-007 through -011.
  - Deleting R8 as it is an unmeasurable requirement.
  - Deleting R10 as it is redundant with TOP-004-0, R1.
  -
  - Deleting R12 as it is redundant with FAC-010 and -011.
  - Removing references to the Balancing Authority and real power output from R13 as they are contractual issues and as such can not be incorporated in a standard. The remaining language should be clarified.
  - R14 and R15 apply to the Generator Operator and as such may be better addressed in other standards. The drafting team should look to find another place for these requirements if possible.
  - Deleting R16.2 as it is redundant with FAC-009-1.
  - Deleting R17 as it is no longer needed if the above mentioned changes are made.

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Deleted: and R11 as they are redundant with IRO-005-2, R9.

Deleted:

Deleted: do not belong in the TOP

  - R18 should be moved to FAC-009-1.
  - Deleting R19 as it can not be measured.
- TOP-003-0:
  - The drafting team should review the 50 MW requirement in R1.1 to determine the size where a generator can have an adverse impact on the Bulk Electric System. See FAC-008-3.
  - Delete Reliability Coordinator when IRO-010-1 is placed in service.
  - Delete R1.3 as it is redundant with IRO-010, R3 as part of the over-all data specification effort.)
  - Re-wording R2 to require general coordination of all facilities that affect Bulk Electric System reliability.
  - Delete R4 in deference to the RC Project.
- TOP-004-1:
  - Delete the reference to SOL in R1
  - Deleting R2 as it is simply the definition of an IROL and is redundant with FAC-010-1 and FAC-011-1...
  - Deleting R3 as it is redundant with FAC-010-1 and FAC-011-1.
  - Re-word R6 for clarity.
- TOP-005-1:
  - Deleting R1 as it is redundant with IRO-010-1.
  - Deleting R1.1 as it is redundant with IRO-010-1.
  - Deleting R2 as it is not a reliability concern.
  - Re-wording R3 to provide more clarity and simplicity.
  - Deleting R4 as it is redundant with INT-001-2, R1.
  - When IRO-010-1 becomes effective, Attachment 1 should be translated into a technical specification. It is only a partial list of required data.
- TOP-006-1:
  - Deleting R1 as it is redundant with FAC-009-1, R2.
  - Deleting the Balancing Authority from R2 as the list of items does not apply. Consider deleting the Reliability Coordinator from R2 as it is redundant with IRO-007-1, R1.
  - Moving R3 to PRC-001.
  - Deleting R4 as it is redundant with BAL-001 and -002 and is also addressed in IRO-010-1, R1 and R3.
  - Deleting R5 as (1) it is good utility practice and not a true reliability requirement or (2) provide clarification on the utilization of alarm processing and to provide definition of important deviations or (3) move the requirement to ORG-004-0.
  - Deleting R6 as it is redundant with BAL-005-0, R17.
  - R7: Consider deleting Balancing Authority as it is covered in BAL-005-0, R8. Consider deleting Reliability Coordinator as it is covered in BAL-008-1, R1.
- TOP-007-0:
  - Rewording R2 to say that the Transmission Operator shall act 'without delay' to return the transmission system to within IROL as soon as possible but not longer than the IROL T_v. The 30 minute time frame should be deleted as it is redundant with IRO-009-1, R2.
  - Delete R4 in deference to the RC Project
- TOP-008-0:
  - Deleting R1 as it is redundant with TOP-007-0, R3.
  - R2: Suggested wording as follows:
    - R2a: For each IROL or SOL that is identified in advance of Real-time, the TOP shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take to prevent exceeding those IROLs or SOLs or to mitigate actual violations *(Violation Risk Factor: Medium) (Mitigation Time Horizon: Operations*

Deleted: as it is redundant with IRO-009-1, R4

Deleted:

Planning)

- R2b. If the involved TOPs cannot agree on a solution or if there is a difference in derived operating limits (IROLs or SOLs), the more conservative solution or limit shall be utilized.

- Deleting R3 as it is a local utility risk consideration and not a reliability issue as currently worded.
- Re-wording R4 for clarity.

- COM-001-1:
  - Re-word R1 to provide clarity to terms such as ‘adequate’ and ‘reliable’. The term ‘telecommunication facilities’ needs to be explicitly defined or re-worded to provide clarity.
  - Define ‘internally’ in R1.1.
  - Delete R1.4 on the basis that it is covered in the new definitions of ‘adequate’ and ‘reliable’. The current phrasing could be interpreted that specific telecommunication devices must be redundant. We believe that this was not the original intent of this requirement. The intent should be to provide redundant telecommunication capability between reliability entities.
  - In R2, periodicity and type of testing, ‘vital’ and ‘special attention’ should be defined.
  - Re-word R3 to make clear that each reliability entity shall notify reliability entities to which you have a communication path prior to changes in telecommunication facilities that would affect them and to resolve any coordination issues.
  - Delete R6 as it is simply an ERO procedural issue. It is assumed that if it belongs in standards that it would be in CIP as opposed to COM. This would then cause the deletion of Attachment 1 and would remove NERC Net User Organization as an applicable entity.
- COM-002-2:
  - Delete the first sentence of R1 as it is redundant with COM-001-1 if the Generator Operator is added as an applicable entity in COM-001-1. Delete the second sentence as it is redundant with PER-003-0, R3.
  - Re-word R1.1 to provide clarity as to the definition of applicable areas. Delete the requirement for firm load shedding as it is not a reliability issue.
  - Re-word R2 to provide clarity for the terminology ‘clear, concise and definitive’. The use of scripts is a possible solution.

Remove applicability and all references to TOP in PER-001-0 due to redundancy with TOP-001-1, R1 with the ultimate goal to eliminate PER-001-0.

There is an industry need to retain good utility practice information that may be deleted from standards requirements. Any requirements so deleted should be considered for movement into appropriate guides or reference documents.

Note that Appendix B is an informative attachment that contains material that should be addressed in the standards revision process. It should not be considered to contain mandatory changes to the standard.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Coordinator	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
X	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
X	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

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☐	Load-Serving Entity	Secures energy and transmission service (and related reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk electric systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X	2. The frequency and voltage of interconnected bulk electric systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk electric systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk electric systems.
X	6. Personnel responsible for planning and operating interconnected bulk electric systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk electric systems shall be assessed, monitored and maintained on a wide area basis.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. The planning and operation of bulk electric systems shall recognize that reliability is an essential requirement of a robust North American economy. Yes
2. An Organization Standard shall not give any market participant an unfair competitive advantage.Yes
3. An Organization Standard shall neither mandate nor prohibit any specific market structure. Yes
4. An Organization Standard shall not preclude market solutions to achieving compliance with that Standard. Yes
5. An Organization Standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	**Explanation**
BAL-001	Real Power Balancing Control Performance
BAL-002	Disturbance Control Performance
BAL-005	Automatic Generation Control
BAL-007	Balance of Resources and Demand
BAL-008	Frequency and Area Control Error
BAL-009	Actions to Return Frequency to within FTL
BAL-010	Frequency Bias Settings
BAL-011	Frequency Limits
FAC-008	Facility Ratings Methodology
FAC-009	Establish and Communicate Facility Ratings
FAC-010	System Operating Limits Methodology for the Planning Horizon
FAC-011	System Operating Limits Methodology for the Operations Horizon
INT-002	Interchange Transaction Tag Communication and Reliability Assessment
IRO-004	Reliability Coordination – Operations Planning
IRO-005	Reliability Coordination – Current Day Operations
IRO-006	Reliability Coordination – Transmission Loading Relief
IRO-007	Monitoring the Reliability Coordinator Wide Area
IRO-009	Reliability Coordinator Actions to Operate Within IROLs
IRO-010	Reliability Coordinator Data Specification and Collection
ORG-004	Transmission Operator Certification – Data Acquisition and Monitoring
PER-003	Operating Personnel Credentials
PRC-001	System Protection Coordination

Related SARs

SAR ID	**Explanation**
Reliability Coordination: Project 2006-06	There are parallels between this SAR for Transmission Operators and the SAR for Reliability Coordinators that must be taken into account in the development of the eventual standards.

Regional Differences

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Appendix A

Reliability Standard Review Guidelines

Applicability
Does this reliability standard clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted? Where multiple functional classes are identified is there a clear line of responsibility for each requirement identifying the functional class and entity to be held accountable for compliance? Does the requirement allow overlapping responsibilities between Registered Entities possibly creating confusion for who is ultimately accountable for compliance?

Does this reliability standard identify the geographic applicability of the standard, such as the entire North American bulk power system, an interconnection, or within a regional entity area? If no geographic limitations are identified, the default is that the standard applies throughout North America.

Does this reliability standard identify any limitations on the applicability of the standard based on electric facility characteristics, such as generators with a nameplate rating of 20 MW or greater, or transmission facilities energized at 200 kV or greater or some other criteria? If no functional entity limitations are identified, the default is that the standard applies to all identified functional entities.

Purpose
Does this reliability standard have a clear statement of purpose that describes how the standard contributes to the reliability of the bulk power system? Each purpose statement should include a value statement.

Performance Requirements
Does this reliability standard state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable Bulk Electric System, consistent with good utility practices and the public interest?

Does each requirement identify who shall do what under what conditions and to what outcome?

Measurability
Is each performance requirement stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement?

Does each performance requirement have one or more associated measures used to objectively evaluate compliance with the requirement?

If performance results can be practically measured quantitatively, are metrics provided within the requirement to indicate satisfactory performance?

Technical Basis in Engineering and Operations
Is this reliability standard based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field?

Completeness
Is this reliability standard complete and self-contained? Does the standard depend on external information to determine the required level of performance?

Consequences for Noncompliance
In combination with guidelines for penalties and sanctions, as well as other ERO and regional entity compliance documents, are the consequences of violating a standard clearly known to the responsible entities?

Clear Language
Is the reliability standard stated using clear and unambiguous language? Can responsible entities, using reasonable judgment and in keeping with good utility practices, arrive at a consistent interpretation of the required performance?

Practicality
Does this reliability standard establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter?

Capability Requirements versus Performance Requirements
In general, requirements for entities to have 'capabilities' (this would include facilities for communication, agreements with other entities, etc.), should be located in the standards for certification. The certification requirements should indicate that entities have a responsibility to 'maintain' their capabilities.

Consistent Terminology
To the extent possible, does this reliability standard use a set of standard terms and definitions that are approved through the NERC reliability standards development process?

If the standard uses terms that are included in the NERC Glossary of Terms Used in Reliability Standards, then the term must be capitalized when it is used in the standard. New terms should not be added unless they have a 'unique' definition when used in a NERC reliability standard. Common terms that could be found in a college dictionary should not be defined and added to the NERC Glossary.

Are the verbs on the 'verb list' from the DT Guidelines? If not – do new verbs need to be added to the guidelines or could you use one of the verbs from the verb list?

Violation Risk Factors (Risk Factor)

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

This is a requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures;

or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the Bulk Electric System. A requirement that is administrative in nature;

Or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

Time Horizon

Deleted: Mitigation

The drafting team should also indicate the time horizon available for mitigating a violation to the requirement using the following definitions:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Violation Severity Levels

The drafting team should indicate a set of violation severity levels that can be applied for the requirements within a standard. (‘Violation severity levels’ replaces the existing ‘levels of non-compliance.’) The violation severity levels may be applied for each requirement or combined to cover multiple requirements, as long as it is clear which requirements are included.

The violation severity levels should be based on the following definitions:

- **Lower: mostly compliant with minor exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
- **Moderate: mostly compliant with significant exceptions** — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
- **High: marginal performance or results** — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.

- **Severe: poor performance or results** — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

Compliance Monitor

Replace, 'Regional Reliability Organization' with 'Compliance Enforcement Authority'.

Deleted: Electric Reliability Organization'

Fill-in-the-blank Requirements

Do not include any 'fill-in-the-blank' requirements. These are requirements that assign one entity responsibility for developing some performance measures without requiring that the performance measures be included in the body of a standard – then require another entity to comply with those requirements.

Every reliability objective can be met, at least at a threshold level, by a North American standard. If we need regions to develop regional standards, such as in under-frequency load shedding, we can always write a uniform North American standard for the applicable functional entities as a means of encouraging development of the regional standards.

Requirements for Regional Reliability Organization

Do not write any requirements for the Regional Reliability Organization. Any requirements currently assigned to the RRO should be re-assigned to the applicable functional entity.

Effective Dates

Must be 1st day of 1st quarter after entities are expected to be compliant – must include time to file with regulatory authorities and provide notice to responsible entities of the obligation to comply. If the standard is to be actively monitored, time for the Compliance Monitoring and Enforcement Program to develop reporting instructions and modify the Compliance Data Management System(s) both at NERC and Regional Entities must be provided in the implementation plan.

Associated Documents

If there are standards that are referenced within a standard, list the full name and number of the standard under the section called, 'Associated Documents'.

Appendix B: List of Comments

The following items are comments received from various sources that shall be considered by the SDT.

COM-001-1

CESDT: (Compliance Elements Standards Drafting Team)

- R1: clarify ‘adequate’, ‘reliable’ and ‘internally’.
- The statement ‘Where applicable, these facilities shall be redundant and diversely routed’ should be a guide and not a requirement. It would also appear that this is duplicated in COM-002-2, R1.
- R2: clarify the term ‘ Special attention’.
- R3: clarify ‘shall provide a means’ and the ‘ability to investigate’.

VRFSDT: (Violation Risk Factors Standards Drafting Team)

- R6: administrative.

Version 0 Industry Comments:

- Gerald Reahlt, Manitoba: There may be redundancy here with Policy 5A Requirement 1.
- Robert Snow: R1 - In section R1, for all but the smallest areas, redundancy and diversely routed telecommunications is required.
- Guy Zito, NPCC: R1 thru R5 - Add “Transmission Owners, Generator Owners, Generator Operators and Load Serving Entities” to the list of FM entities this applies to.
- Ralph Rufrano, NYPA: NPCC's participating members recommend changing R1 to;
  Each Reliability Authority, Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator and Load Serving Entity shall provide adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability. Where applicable, these facilities shall be redundant and diversely routed. -and changing R2 – R5 from "Each Reliability Authority, Transmission Operator, and Balancing Authority shall" To "Each Reliability Authority, Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator and Load Serving Entity shall" -Remove R6 and attachment 029-1 should be removed. Those procedures apply to NERCnet users, which is a small subset of community that R1 – R5 apply to. Also, these procedures are the steps for obtaining and using NERCnet. Those procedures should not be part of a Reliability Standard.

FERC Order 693:

- Expand the applicability of the standard to include Generator Operators and Distribution Providers and include requirements for their telecommunication facilities (or as an alternative to applying this Reliability Standard to Generator Operators and Distribution Providers, develop a new Reliability Standard that will address the requirements for telecommunication facilities applicable to Generator Operators and Distribution Providers).
- Identify specific requirements for telecommunications facilities for use in normal and emergency conditions that reflect the roles of the applicable entities and their impact on Reliable Operation
- Include adequate flexibility for compliance with the Reliability Standard, adoption of new technologies and cost-effective solutions

COM-002-2

CESDT:

- R1, part 2: clarify ‘Such communication shall be staffed and available for addressing a real-time emergency condition’.
- R2: clarify ‘clear, concise and definitive manner’. Define ‘directive’.

V0 Industry Comments:

- Mike Kormos, PJM: In a Market environment voice communication with generators is not necessarily required.
- FRCC: R1 - Reliability Authority should be included in this requirement.
- Ray Morella, First Energy: R2 - All groups active in the industry should be required to report sabotage incidents and security breaches.
- Guy Zito, NPCC: R4 - Even though this is a direct translation of the existing Policy, NPCC requests a clarification of the repeat back requirements, specifically are they for emergency, abnormal, normal, all of the above, provide specific examples.

FERC Order 693:

- Expand the applicability to include distribution providers as applicable entities.
- Include a new requirement for the Reliability Coordinator to assess and approve actions that have impacts beyond the area view of a Transmission Operator or Balancing Authority.
- Require tightened communications protocols, especially for communications during alerts and emergencies.
    - Alternatively, develop a new Reliability Standard that responds to Blackout Report Recommendation No. 26 in the manner described above.
- Include APPA’s suggestions to complete the Measures and Levels of Non-Compliance.

PER-001-0

V0 Industry Comments:

- Southern Company: Compliance Monitoring Process - The Data Retention requirement for this standard should be 1 year. The probability exists that over time, the job description and perhaps other documentation will be modified. There should not be a requirement to keep past versions of authorizing documents for an indefinite period of time.
- Bill Squib, ECAR: In the Compliance Monitoring Process… if the Reset Period is One Calendar Year, then why is the Data Retention Permanent. In addition, what kind of data is considered for Data Retention. Surely a 10-year old Job Description that has been updated several times does not need to be retained permanently.

TOP-001-1

CESDT:

- R8: essentially duplicated in other areas; clarify reactive power balance.

V0 Industry Comments:

- Michael Moltane, ECAR: (1) Need good, clear definition of "Reliability Emergency" for this to work. Otherwise we will get into the endless and age-old discussion of "what is an emergency?" (2) R1: Recommend adding wording to the sentence "clear decision making authority" that such authority should be documented and incorporated into Operating Procedures so that there will not be any confusion in real time emergencies as to who is responsible for what, and to whom.
- Roman Carter, Southern Company: (1) This req. states "The RA, BA, and TO shall have the responsibility…". The original language in Policy 5 for this requirement uses Operating Authority and this includes entities such as the GO, TO, and BA but not the Reliability Coordinator. Throughout this V-0 Standard the RA is subsituted for the RC even within this requirement. Since the original policy says RCs are excluded, this poses a conflict for this requirement. This is also in Req's 2, 4, 5. (2) There are times when a Generator Operator must act quickly and may not have time to notify the Transmission Operator. There needs to be an exception here (like that listed in 7C for the RA and TOP) for emergency situations that allows follow up notification by the GO.
- Southern Company: R4 and R6 - Should specify that the local RA will handle all communications with other potentially impacted Reliability Coordinators. As written (Reliability Authority or …), these requirements could lead to multiple notifications and potential confusion as to exactly what action is going to happen or has taken place. In general, all communications with adjacent Reliability Authorities should be through the local Reliability Coordinator. (Note that R4 may intend that RA contact other RAs, etc., but this is not clear and could easily be misinterpreted.)
- Peter Henderson, IMO: In the sentence: "Under these circumstances the Transmission Operator or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive …" The use of "or" is confusing and may create ambiguity. The specific role of entity responsible for 'providing' and 'receiving' information needs to be clarified. Should this be combined responsibility applicable to all or for any? **For the purposes of effective implementation/enforcement of these standards, we recommended that the associated measures, compliance monitoring process and levels of non compliance should also be (a) simultaneously mapped/specified where these exist already and (b) specifed/addressed in the very near future, where these do not exist today for consistency. **This comment also applies to Standards 19, 21, 26, 34 and 35.

FERC Order 693:

- Include Measures and Levels of Non-Compliance for Requirement R8.
- Consider adding other Measures and Levels of Non-Compliance in the Reliability Standard.
- Consider revising Requirements R7.2 and R7.3 to provide that the transmission operator may notify the Reliability Coordinator or the Balancing Authority that it is removing facilities from service as suggested by Santa Clara.

TOP-002-2

CESDT:

- R1, part2: clarify 'Transmission Operator shall be responsible for using available personnel and system equipment'.
- R2: too vague
- R3: too vague; clarify 'coordinate'.
- R4: too vague; clarify 'coordinate'.
- R12: duplicated in FAC-013.

- R13: duplicated in MOD-024 & MOD-025.
- R17: incorrectly written.
- R19: too vague; clarify 'accuracy'; determine timeliness of model.

Regional Reliability Standards Working Group (RRSWG):

- R6: remove 'in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements'.
- R12: remove 'in accordance with filed tariffs and/or regional Total transfer Capability and Available Transfer capability calculation processes'.

V0 Industry Comments:

- Alan Johnson, Mirant: Concerned that the translation from Control Area to BA or TOP creates a new requirement for the GOP. The proposed language allows the possibility of the GOP having to perform tests at the request of both the BA and TOP. The GOP should only be required to perform 2 seasonal capability tests per year (winter and summer) within pre-defined parameters.
- Southern Company: General - Hierarchical structure seems to be implied, but not explicitly defined in the translation of Control Area and Reliability Coordinator language to functional model language. May want to consider writing requirements such that all Balancing Authorities and Transmission Operators within a given Reliability Authority's area should coordinate their operations planning, etc.
- PG&E: R3, R4, R5 - The parentheticals "where confidentiality agreements allow" imply that confidentiality agreements trump coordination of operational plans needed to assure system reliability. They should be eliminated. Reliability Authorities would then be responsible for coordination between each other, etc. Seems confusing and/or difficult to follow as written.
- Roman Carter, Southern Company: (1) 4, 5 - Requirement says LSE, TSP, and GO coordinate with BA (where confidentiality agreements allow). Under the F.M., the BA can delegate certain tasks that prevent the BA from meeting the Conf. Agreement in order for the BA to meet the obligations of the BA. Version-0 Standard should recognize this ability. (2) Requirement states without intentional delay. How is this enforceable? The burden of proof is with the enforcement organization.
- Ray Morella, First Energy: R7 - Need to explicitly and precisely define what N-1 contingency means.
- Raj Rana, AEP: R18 - R18 only needs to state that the BALANCING AUTHORITIES shall, without any intentional time delay, communicate the information described in the requirement R15 above to their RELIABILITY AUTHORITY, or add such statement to R15. R17 already requires notification to the RA, and these were the activities that Policy today requires notification to the RA, as referenced in Policy 6A R6.1 - 6.5.
- Peter Lebro, National Grid: R3, R4, R5, R12, R17: Confidentiality of information should not be a factor when it comes to reliability – this needs to be addressed otherwise Companies may hide behind the confidentiality clause and not provide the data necessary to conduct operational reliability assessments and coordinate reliable operations.

FERC Order 693:

- Delete references to confidentiality agreements in Requirements R3 and R4, but address the issue separately to ensure that necessary protections are in place related to confidential information.
- Require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.
- Require next day analysis of minimum voltages at nuclear power plants auxiliary power busses.
- Require simulation contingencies to match what will actually happen in the field.

TOP-003-0

VRF:

- R4: poorly written.

V0:

- Peter Lebro, National Grid: Standard 16:R1, Standard 37:R4: In the standards it states outage data (generation and transmission) is only required to be submitted by noon of the day ahead, the emphasis should be on submitting the data as soon as it is known but no later that noon day ahead.
- Anita Lee, AESO: CMP - Third paragraph - The RA should "direct" the cancellation of an outage, not "request".
- Robert Snow: Outage information is needed by neighboring reliability authorities much sooner than one day pror to the outage.

FERC Order 693:

- Include a new requirement to communicate longer term outages well in advance to ensure reliability and accuracy of ATC calculations.
- Make any facility below the voltage thresholds that, in the opinion of the Transmission Operator, Balancing Authority, or Reliability Coordinator, will have a direct impact on the operation of the Bulk Power System, subject to Requirement R1 for planned outage coordination.
- Incorporate an appropriate lead time for planned outages.

TOP-004-1

CESDT:

- R1: TOP cannot always operate within IROL.
- R2: need to be able to measure ‘planning to prevent such an occurrence’.
- R3: same comments as R2; clarify ‘when practical’.
- R5: clarify ‘every effort to remain connected’ and ‘imminent danger’.

V0:

- Brandian, ISO-NE: In the existing policy the overall role of monitoring of SOL or IROL was assigned to a Control Area. In the applicable version 0 standards a clarification on the role and relationship between Reliability Authority and Transmission Operator should be made with regards to the monitoring of SOL & IROL.
- Guy Zito, NPCC: (1) These Standards must clearly identify, define and provide examples of what a SOL and IROL are. The reason for this is that this is not consistently interpreted by industry. (2) (Also in R5) This needs to be clarified whether these requirements have to be fulfilled by both presently worded RA (i.e. new proposed terminology RC) and TO - “individually or jointly”. It is not clear that who would be overall monitor. A more clear role needs to be identified in this standard. Also Reliability entity should be termed as ‘RC’.
- Robert Snow: Transmission Security during operation should conform to the applicable portions of Table 1 in the planning standards.

- Vinod Kotecha, Con Edison: There remains vagueness in the application of Interconnection Reliability Operating Limits (IROL) and guidelines for how it is calculated. The RC has been designated as being responsible for maintaining the interconnection within IROLs, however debate on how these should be calculated continues.
- Tracy Edwards, BPA: R5 indicates that every effort shall be made to remain connected to the Interconnection. However the second sentence of the requirement implies that it may be acceptable to disconnect from the Interconnection if there is imminent danger of violating an IROL or SOL. There can be other conditions other than violating IROL's or SOL's that place the system at great risk. In fact, violating an IROL or SOL in itself does not necessary mean the system is at imminent risk. Therefore, change the second sentence of R5 to read as follows: The Reliability Authority or Transmission Operator may take such actions as disconnecting from the Interconnection, as it deems necessary, to protect its Area.
- Roman Carter, Southern Company: It is not practical to say the RA and the TOP operate, when practical, to protect against instability, separation, or cascading outages. Recommend removing "when practical" because when is it ever practical to allow cascading outages.

FERC Order 693:

- Modify Requirement R4 to state that the system should be restored to respect proven limits as soon as possible, taking no more than 30 minutes.
- Define high risk conditions under which the system must be operated to respect multiple outages in Requirement R3.

TOP-005-1

V0:

- Brandian, ISO-NE: Applicability - Add Generator Owners and Load Serving Entities. Extend R5 to include these Functional Model entities.
- Ed Riley, CAISO: R1 - Current policy is for data to be updated every 10 minutes, and is in Standard 15. This rate is too slow and should be increased (every 4-10 seconds) when possible. This should be addressed in Version 1.
- Robert Snow: In Attachment 1, the generator data should include status of voltage control and power system stabilizer facilities.
- Tracy Edwards, BPA: Attachment 015-1: Need a time frame for this data, it is not measurable as it reads now.
- Peter Lebro, National Grid: National Grid USA would like to make the following recommendations to be considered when drafting the next draft of Version 0. Standard 15: There should be a requirement on generators to provide the necessary data as there is a requirement on the PSE’s (R6), a paragraph R7 should be inserted which reads ‘Generation Operators shall provide information requested by their host Balancing Authority and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.’

FERC Order 693:

- Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.
- Delete references to confidentiality agreements, but address the issue separately to ensure that necessary protections are in place related to confidential information.

TOP-006-1

CESDT:

- R3: quantify relay information that is required and the scope of the relays to be included; clarify what constitutes ‘appropriate technical information’.
- R6: clarify ‘measure requirement’

VRF:

- R1, 1.1 & 1.2: may need ‘available in emergency situation’
- R3: define ‘appropriate’.
- R4: what information is required and what is a load pattern?

V0:

- Guy Zito, NPCC: Associated Measure, Compliance Monitoring Process and Levels of Non Compliance are missing and needs to be defined in this standard simultaneously.
- Michael Moltane, ECAR: R1.1: Should clarify that the the Gen Operator needs to provide “normal and emergency capability for use”, as opposed to current wording of just “.all generation resources available for use” (i.e., stretch capability, maximum run time for emergency capability, etc.). R7: Indicates that entities shall “monitor system frequency”……recommend adding wording to indicate frequency shall monitor system frequency at multiple points on their system.
- Alan Boesch, NPPD: R4 - In the Functional Model load forecasts are developed by the Load Serving Entity and provided to the Balancing Authority. The BA sends the agregated information to the RA. The TOP is not involved in this process. Please change the requirement to match the functional model.
- Various entities: R4 - Load forecasting is the starting point for planning capacity for obligations and thus, deemed to be required for reliability.

FERC Order 693:

- Include a new requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk Power System.
- Clarify the meaning of “appropriate technical information” concerning protective relays.

TOP-007-0

V0:

- Ed Riley, CAISO: Measures - 2nd paragraph should be changed to read “…within IROL or SOL…” The CAISO believes that suggesting that the determination of an SOL becoming an IROL after the fact is inappropriate.
- Eric Grant, Progress: R1-R5 - In general, unless better bounds/criteria are set for the determination of IROLs, this standard will not be enforceable or auditable.
- Phil Creech, Progress: "Applicability" for this standard should include "Reliability Authorities".
- Various entities: R5 - This should be considered as a compliance monitoring or administrative procedure rather than a standard.

- Martin Huang, BC Transmission: R1 and M1 both requires the Reliability Coordinate be informed of any IROL or SOL violation but the level of non-compliance only applies when the limit is exceeded more than 30 minutes and none for failure to report the violation.
- Tracy Edwards, BPA: (1) Compliance Monitoring Process: (bullets following the first paragraph) 2) … Is vague and not measureable 3) … Would not necessarily make it an IROL. 4) … Would not nessarly make it an IROL. 5) … Is vague and there is no unacceptable loss of load definition for NERC that is measurable. (2) Compliance Monitoring Process: (first paragraph, second sentence) If this sentence were true the violation would have been an IROL to begin with. Give an example of this scenario. (3) Give an example of how you would show evidence something was evaluated. This does not seem like a possible measure. Also the RC may not have needed to give any additional direction and would therefore not have any evidence as required by the measure.
- Linda Campbell, FRCC: Standard 008, M1-M3. What kind of evidence is anticipated? The word evidence can be very subjective and broad. Also the RA should be removed from these measures.

FERC Order 693:

- Consider comments from APPA, FirstEnergy and SoCal Edison that the Reliability Standards would benefit from the elimination of overlapping matters in TOP-007-0 and TOP-008-1.
- Consider comments from the NRC that raised some significant issues regarding nuclear power plants voltage requirements.

TOP-008-0

CESDT:

- R2: clarify ‘prevent the likelihood’.
- R4, part 2: clarify ‘in all operating timeframes’.

Maureen E. Long
Standards Process
Manager

August, 06, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Comment Periods Open

The Standards Committee (SC) announces the following standards action:

SAR for Real-Time Transmission Operations and Balancing of Load and Generation (Project 2007-03) Posted for 30-day Comment Period August 9–September 7, 2007

The second draft of the SAR for Project 2007-03 Real-time Transmission Operations and Balancing of Load and Generation proposes modifying the following standards that relate to various aspects of Reliability Coordination:

- COM-001-1 Telecommunications
- COM-002-2 Communications and Coordination
- IRO-004-1 Reliability Coordination – Operations Planning
- IRO-005-2 Reliability Coordination – Current Day Operations
- IRO-006-3 Reliability Coordination – Transmission Loading Relief
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination
- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

The modifications will address concerns raised by FERC and stakeholders and will bring the standards into conformance with the latest version of the Reliability Standards Development Procedure and the ERO Sanctions Guidelines. Please use the comment form to provide comments on the second draft of this SAR.

Standards Development Process

The NERC posting and balloting procedures are described in the *Reliability Standards Development Procedure Manual*, which contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for Second Draft of SAR for Project 2007-03 — Real-time Transmission Operations and Balancing of Load and Generation

Please use this form to submit comments on the proposed SAR. Comments must be submitted by **September 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.net with the words "Real-time TOP_BA SAR" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
Telephone:		
E-mail:		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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☐ **FRCC**	☐	2 — RTOs and ISOs
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☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
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Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

The SAR for Real-time Transmission Operations and Balancing of Load and Generation (Project 2007-03) was posted for comment from May 15 through June 13, 200. The SAR Drafting Team considered the comments and corrected all noted typographical errors and made the following revisions to the SAR:

- Added IRO-004, IRO-005 & IRO-006 to the scope of standards to be reviewed to eliminate redundant requirements.

- Clarified that the reason for recommending the deletion of TOP-002-2, R8 is because the requirement is unmeasurable.

  R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.)

- Removed the recommendation for deleting TOP-002-2, R11:

  R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.

- Reworded the recommendation in TOP-002-2, R14 & R15 to clarify that these requirements may be better addressed in other standards.

  R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

  R14.1. Changes in real output capabilities.

  R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

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  R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

Please review the revised SAR and then answer the question on the following page. Please submit your comments by **September 7, 2007** to sarcomm@nerc.com with the words “Real-time TOP_BA SAR” in the subject line.

1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☐ Yes

   ☐ No

   Comments:

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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Name: Thad K. Ness		
Organization: AEP		
Telephone: 614-716-2053		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☒	1 — Transmission Owners
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1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☒ Yes

   ☒ No

   Comments: We agree with the concept of eliminating redundancy in the NERC Standards. However, Project 2006-08 involves re-writing IRO-006 in three phases and is currently in phase one. Any changes required to IRO-006 to eliminate redundancy of Transmission Operator and Balancing Authority requirements in other standards should be coordinated with, and handed off to, the Project 2006-08 IRO-006 Standard Drafting Team. Thus, IRO-006 should not be included in the scope of this SAR. We have no objection to including IRO-004 and IRO-005 into the scope of this project and we stand by our comments to the first SAR.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Jason Shaver		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☒	1 — Transmission Owners
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1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☐ Yes

   ☒ No

   Comments: The SDT has not provided any information as to scope of work that will be performed on IRO-004, 005 and 006 in the posted version of the SAR. Therefore ATC does not agree with the expanded scope. The SAR SDT must provide information as to why these standards must be worked on as part of this effort. We request that the SAR SDT provided the necessary information and post a revised version of the SAR for comment.

   Additional comments:

   Issue 1:
   A majority of comments submitted on Question 2 (Initial SAR posting) did not support the SDT proposal to remove SOL requirements from NERC's Reliability Standards. ATC believes that SOLs are a BES issue and must continue to be part of NERC Reliability Standards. ATC does not agree with the SDT proposed compromise that would limit Reliability Standards to only requiring monitoring of SOL. (Note: The SAR provides little to no justification as to why SOL should be removed from NERC Reliability Standards.)

   "Question 2 (initial SAR posting): The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on 'good utility practice'. Do you agree?"

   Issue 2:
   ATC continues to disagree with the current scope of work. We find that scope of work's description is overly prescriptive and not complete. It seems that the SAR is attempting to remove requirements that address SOL conditions from NERC standards but that is never specifically stated in the SAR. It's also import to note that in Appendix B of the SAR no specific request was made to remove SOL from NERC standards. Many of the requests in Appendix B only support clarification and removal of redundant requirements.

   It's our position that the effort to remove SOLs from NERC standards will reduce interconnection reliability. Therefore ATC can not support this SAR until a proper scope of work is developed. The scope should be limited to clarifying existing requirements by; removing redundancy, better alignments of requirements to measures and removal/clarification of ambiguous language.

   Issue 2a:

   COM-001 Is currently being worked on in projects 2006-04 & 2006-06
   COM-002 Is currently being worked on in projects 2006-06 & 2007-02
   IRO-004 Is currently being worked on in project 2007-02
   IRO-005 Is currently being worked on in project 2007-02 & 2007-18

IRO-006 Is currently being worked on in project 2006-08

Lastly ATC believes that this project should be delayed until the all previously identified efforts have been completed in order to insure an efficient work flow. If this project is moved into the standard development phase five Standards will have parallel efforts on going. Coordination will be extremely difficult if not impossible to manage.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name: Edward Davis		
Organization: Entergy Services		
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E-mail: edavis@entergy.com		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☒ Yes

   ☐ No

   Comments:

   We have additional comments on other parts of this revised SAR.

   COMMENTS ON TOP-001-1

   We suggest the deletion of the first recommended change to TOP-001-1:

   - Removal of R2 due to redundancy with R1. R2 largely describes an ill-defined procedure which should not be in a standard.

   This suggested change was revised from the first posting of this SAR, changing "with R3" to "with R1". Each of the three requirements of TOP-001-1 address different responsibilities of a TOP. R1 states a TOP has responsibility and authority, R2 states the TOP will take action, and R3 states the TOP and others will comply with the directives of the RC, or TOP. We do not agree R2 contains an ill-defined procedure.

   However, we may agree to remove TOP-001-1 R2 because it may be redundant with TOP-008-1 R1.

   We also suggest revising the TOP-001-1 draft change from:

   Eliminating R5 in light of possible redundancy with IROL standards.

   to:

   Eliminating R5 IF REDUNDANT with IROL standards.

   COMMENTS ON TOP-002-2

   The first suggestion of TOP-002-2 suggests deleting R1 as it is redundant with TOP-008-1 R1. We recommend changing the TOP-008-1 reference to R2, rather than R1. We agree that TOP-002-2 can be eliminated as being redundant with TOP-008-1 R2, not TOP-008-1 R1.

   We do not agree with the suggestion that TOP-002-2 that R4 should be deleted. TOP-002-2 R4 is a requirement on the BA and TOP while IRO-005-2 R9 is a requirement on the RC.

We do not agree with the suggestion of deleting TOP-002-2 R6 as it is redundant with IRO-005-2 R9. However, we do agree with deleting R6 if the reason is changed to being redundant with EOP-001 R3.2. With this change we agree with deleting TOP-002-2 R6.

We do not agree with the suggestion to delete TOP-002-2 R7 and R9. Both these requirements should remain in TOP-002. The reason for the suggested deletion is R7 and R9 are redundant with BAL-007 through BAL-011. However, BAL-007 through BAL-011 were not approved by the Ballot Body and are not NERC standards. Therefore TOP-002-2 R7 and R9 are not redundant and the suggestion should be deleted.

TOP-002-2 R12 should not be deleted. We believe it is not redudant of the requirements in FAC-010 SOL Methodology for the Planning Horizon and FAC-011 SOL Methodology for the Operations Horizon.

COMMENTS ON TOP-004-1

The first entry for TOP-004-1 suggests deleting reference to SOL in R1. Deleting R1 indicates TOPs are not required to operate within SOLs. TOPs should operate within SOLs and this entry should be deleted from the SAR.

COMMENTS ON TOP-005-1

It is suggested deleting R1 and R1.1 as they are redundant with IRO-010-1. However, IRO-010-1 is not an approved standard so R1 and R1.1 should remain in TOP-005-1. That is unless the SAR is changed to say R1 and R1.1 should be deleted after IRO-010-1 is approved and has provisions that duplicte R1 and R1.1.

It is suggested that R4 be deleted from TOP-005-1. Do not delete R4 (PSE provides information as requested for reliability assessments and coordinate operations) as it is significantly more encompassing than INT-001-2 R1 (which only requires PSEs provide Arranged Interchange to the IA.) If anything is done INT-001-2 R1 should be deleted and TOP-005-1 R4 should be kept.

COMMENTS ON TOP-006-1

It is suggested that R1 be deleted from TOP-006-1. Do not delete R1 (report facility status) as it is significantly different than FAC-009-1 R2 (report facility ratings). They are not the same.

It is suggested that R4 be deleted from TOP-006-1 as the requriement is redundant with BAL-001 and -002 and is addressed in IRO-010 R1 and R3. R4 should only be deleted if the requirements are actually included in the final approved IRO-010.

It is suggested that R6 (use sufficient metering) be deleted from TOP-006-1 as the requirement is redundant with BAL-005-1 (annually check and calibrate time error and frequency devices). We suggest R6 be kept in TOP-006-1 since the requirements are not in BAL-005-1.

COMMENTS ON TOP-007-0

It is suggested to delete R4 in deference to the RC Project. We suggest R4 be kept in TOP-007-0 until the RC Project is a NERC approved standard.

COMMENTS ON TOP-008-0

It is suggested to delete R1 (relieve IROL or SOL) as it is redundant with TOP-007-0 R3 (relieve IROL). We suggest R1 be kept in TOP-008-0 or include SOLs in TOP-007-0 R3.

COMMENTS ON COM-001-1

No Comments.

COMMENTS ON COM-002-2

The first bullet is to delete the second sentence of COM-002-2 R1 as it is redundant with PER-003-0 R3. However, there is no R3 in PER-003-0 so we recommend the second sentence stay in COM-002-2 R1.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:	Dave Folk	
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E-mail:	folkd@firstenergycorp.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☒	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*
Sam Ciccone	FE FERC Compliance Department		
Doug Hohlbaugh	FE FERC Compliance Department		

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

The SAR for Real-time Transmission Operations and Balancing of Load and Generation (Project 2007-03) was posted for comment from May 15 through June 13, 200. The SAR Drafting Team considered the comments and corrected all noted typographical errors and made the following revisions to the SAR:

- Added IRO-004, IRO-005 & IRO-006 to the scope of standards to be reviewed to eliminate redundant requirements.

- Clarified that the reason for recommending the deletion of TOP-002-2, R8 is because the requirement is unmeasurable.

  R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.)

- Removed the recommendation for deleting TOP-002-2, R11:

  R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.

- Reworded the recommendation in TOP-002-2, R14 & R15 to clarify that these requirements may be better addressed in other standards.

  R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

  R14.1. Changes in real output capabilities.

  R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

- Clarified the deletion requested in TOP-004-1, R1 is the reference to 'SOLs'

  R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

Please review the revised SAR and then answer the question on the following page. Please submit your comments by **September 7, 2007** to sarcomm@nerc.com with the words "Real-time TOP_BA SAR" in the subject line.

1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☒ Yes

   ☐ No

   Comments: FirstEnergy, like some other entities, is concerned that the SAR drafting team did not provide an opportunity to comment on their proposed resolution to the SOL issue identified in Question 2 of the previous draft's comment form. While it is not crystal clear to us that the SAR Drafting Team intended to removal all references to SOLs from the Standards, it is also not clear to us that the revisions made to the SAR by the drafting team adequately addressed the views expressed by the commenters. The messages sent by the SAR Drafting Team in the Comment Summary and the individual responses to comments seem mixed. The response to comments document indicates that the SAR drafting team will pass comments on to the Standard Drafting Team; however, the modifications to the SAR were minor and did not provide any guideance to the Standard Drafting Team on the method for applying these comments. Furthermore, the SAR Drafting Team did not seem to embrace the comments provided by the industry on this topic. We understand that the comments received were provided by a small segment of the industry; however, we are also aware that the communication from the commenters was was clear. The majority of commenters supported the retention of SOLs in the standards as necessary and appropriate.

   All of this being said, while we clearly do not agree with the wholesale removal of SOLs from the Standards, but we do support the removal of SOLs from TOP-004-1 Requirement 1 as specified in the SAR. We support this because the methodology used to determine SOLs, and for that matter, IROLs is not clearly defined. This means that one organization may be using a methodology that produces an eight hour SOL while another's method may produce a one hour SOL. We believe that the company using an eight hour limit should not be bound as tightly to that limit as a company that uses a one hour limit. Therefore, the SAR should direct the Standard Drafting team to develop, or at least investigate the development, of a limit methodology applicable across all of NERC that can be consistently applied.

   FE also offers the following comments to specific items revised in the SAR:
   ☐ Added IRO-004, IRO-005 & IRO-006 to the scope of the standards to be reviewed to eliminate redundant requirements.
   FE agrees

   ☐ Clarified that the reason for recommending the deletion of TOP-002-2, R8 is because the requirement is unmeasurable.
   R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.
   FE disagrees with this direction.
   There does not appear to be an industry agreed upon justification given to remove this requirement in lieu of developing 'R8' along with eliminating ambiguity in the existing measure for this requirement described in 'M3'.

   ☐ Removed the recommendation for deleting TOP-002-2, R11:
   R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators

shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.

FE agrees

☐ Reworded the recommendation in TOP-002-2, R14 & R15 to clarify that these requirements may be better addressed in other standards.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but no limited to:

R14.1. Changes in real output capabilities

R15. Generator Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

FE agrees, but with the following provision:

The SDT should also develop clear justification for addressing these requirements in "other standards" while identifying the appropriate "other standards"; and, if justified, the SDT should develop a clear, industry approved plan to transfer these requirements to those identified standards.

☐ Clarified the deletion requested in TOP-004-1, R1 is the reference to 'SOLs'

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

FE agrees, but with the following provision:

The SDT should also consider verbiage in the standards with regard to how SOLs can still be conveyed with some indirect measure (non-sanctioned) of importance in development of the applicable standards.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ ERCOT	☒	1 — Transmission Owners
☐ FRCC	☐	2 — RTOs and ISOs
☐ MRO	☐	3 — Load-serving Entities
☒ NPCC	☐	4 — Transmission-dependent Utilities
☐ RFC	☐	5 — Electric Generators
☐ SERC	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ SPP	☐	7 — Large Electricity End Users
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	☐	10 — Regional Reliability Organizations and Regional Entities

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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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- Clarified the deletion requested in TOP-004-1, R1 is the reference to 'SOLs'

  R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

Please review the revised SAR and then answer the question on the following page. Please submit your comments by **September 7, 2007** to sarcomm@nerc.com with the words "Real-time TOP_BA SAR" in the subject line.

1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☐ Yes

   ☒ No

   Comments: Both IRO-006-3 and draft IRO-006-4 have the TOP listed in applicability section. However, neither actually has any requirement in the standard. They simply reference the TOP in the requirements.

   We think that the scope should not be restricted to only eliminate redundancy in IRO-004, -005 and -006 but should permit other changes in those standards. Hydro-Québec TransÉnergie would probably have some proposition to make because of the characteristics of Québec Interconnexion.

   The SAR drafting team should modify the scope so that all requirements to monitor and control flows within SOLs are not eliminated. While the SAR drafting team points out in their response to the comments that NERC's definition defines an SOL as local, eliminating all requirements to monitor and control to SOLs will be detrimental to reliability. Multiple SOLs occuring on a system may be a sign of an undetected IROL or, if left unchecked, propagate into an IROL. This was the cause of the August 14th blackout. Clearly there should be an obligation on the part of the TOP and RC to monitor and mitigate these limits to prevent such propagation.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
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- Clarified that the reason for recommending the deletion of TOP-002-2, R8 is because the requirement is unmeasurable.

  R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.)

- Removed the recommendation for deleting TOP-002-2, R11:

  R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.

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  R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

- Clarified the deletion requested in TOP-004-1, R1 is the reference to ‘SOLs’

  R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

Please review the revised SAR and then answer the question on the following page. Please submit your comments by **September 7, 2007** to sarcomm@nerc.com with the words “Real-time TOP_BA SAR” in the subject line.

1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☒ Yes

   ☒ No

   Comments:

   Since this comment form has only one question, we are checking both boxes - yes for inclusion of IRO-004, -005 and -006 but no to some of the changes made or not made to the previous SAR, and provide additional comments as follows:

   (1) Specific to the bullets provided in the background section, above, we agree with the first bullet and do not have any comments on the 2nd to 4th bullets. However, we do not agree with the 5th bullet to remove reference to SOL from TOP-004-1 R1, which requires that "Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs)."

   In the SAR DT's response posted in Consideration of Comments, it states that "Based on stakeholder comments, the SAR DT is proposing to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs." Removing reference to SOL in TOP-004-1 R1 contradicts with the above statement. Further, we continue to strongly disagree with the SDT that TOPs are not required to operate within SOLs - We agree that all SOLs are not created equally but there are those SOLs which have a tremendous impact on system reliability, much in the same way as IROLs, and given the appropriate conditions, these very SOLs, if not complied with, could have a highly detrimental impact on the system and subsequntly the interconnection (also see comments by others in the Consideration of Comments).

   (2) In the Consideration for Comments, the SAR DT responded to our previous comments under Question #9, from TOP-001 R2 to TOP-002 R18. We appreciate that the DT's concurs with most of our comments.

   However, we are unable to find the DT's response to our other comments, from TOP-003 to TOP-008. A review of the revised SAR indicates that changes proposed in the previous SAR for these standards/requirements would remain, some of which we expressed disagreement in our previous comment submission. Not seeing a response from the SAR DT, we are uncertain whether our comments were overlooked, or the DT concluded that our comments did not result in any material changes to the proposed revisions to these standards.

   Assuming it was an oversight, we are providing our comments on TOP-003 to TOP-008 again as follows. We would appreciate seeing the DT's response to these comments when the Consideration of Comments on this revised SAR is posted.

   TOP-003-0

   R3: the SDT suggests deleting R1.3 as it is redundant with IRO-010, R3 as part of the over-all data specification effort. We believe the referenced requirement should be R4.

   TOP-004-0

R1: the SDT suggests deleting R1 as it is redundant with IRO-009-1, R4. We disagree with this. SAR IRO-009-1 holds the RC responsible for operated within IROL. We feel strongly that the TOP must also operate its system to respect IROL. Further, we need to defer any changes to remove or modify SOL until after the definition of Adequate Level of reliability is defined. We also provided other reasons for retaining it. Please see our comments on Q2, above.

R2: the SDT suggests deleting R2 as it is simply the definition of an IROL and is redundant with FAC-010-1 and FAC-011-1. We disagree with this proposal since R2 requires TOP to operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. FAC-010-1 and FAC-011-1 deal with the methodology to determine SOL and IROL. They hold different entities for doing very different things altogether.

R3: We disagree with removing this requirement for the above same reason.

TOP-005-1

R2: the SDT suggests deleting this requirement. We agree that R2 is not a reliability requirement, but the SDT needs to recommend a home for entities that receive data from the ISN that it must sign the NERC Confidentiality Agreement for "Electric System Reliability Data".

TOP-006-1

R1: the SDT suggests deleting R1 as it is redundant with FAC-009-1, R2. We disagree with this proposal since R1 deals with real-time data such as facility status, resource availability; whereas FAC-009-1 deals with establishing ratings.

R4: the SDT suggests deleting R4 as it is redundant with BAL-001 and -002 and is also addressed in IRO-010-1, R1 and R3. We disagree as R4 requires the operating entities to do things that are very different from any of BAL-001, BAL-002 and IRO-010-1.

R7: the SDT considers deleting Balancing Authority as it is covered in BAL-005-0, R8 and deleting Reliability Coordinator as it is covered in BAL-008-1, R1. We do not agree with both. In the first case, the requirements for the BA in R7 is to monitor system frequency which is different than those in BAL-005-0, R8 which specify the data and metering requirements. In the second case, BAL-008 doesn't yet exist (failed ballot).

TOP-008

R3: the SDT suggests deleting R3 as it is a local utility risk consideration and not a reliability issue as currently worded. We do not agree with the deletion since the requirement implies that the action taken by the TOP has interconnected system implication.

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
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   ☐ Yes

   ☒ No

   Comments: Both IRO-006-3 and draft IRO-006-4 have the TOP listed in applicability section. However, neither actually has any requirement in the standard. They simply reference the TOP in the requirements.

   Because there is not the typical question regarding additional comments in the comment form, we will provide those here.

   R8 in TOP-002-2 should not be eliminated because it is not measurable. The standards drafting should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible deletion may be appropriate, but the industy, not the SAR drafting team, should not be making this determination.

   Because the SAR states that R14 and R15 in TOP-002-2 may be better addressed in other standards, we are concerned that the standards drafting team may delete these requirements under the assumption that another team will add them to another standard. This standard drafting team should not remove these requirements unless they simply are not needed for reliability or added to another standard in conjunction with the deletion.

   The SAR drafting team should modify the scope so that all requirements to monitor and control flows within SOLs are not eliminated. While the SAR drafting team points out in their response to the comments that NERC's definition defines an SOL as local, eliminating all requirements to monitor and control to SOLs will be detrimental to reliability. Multiple SOLs occuring on a system may be a sign of an undetected IROL or, if left unchecked, propagate into an IROL. This was the cause of the August 14th blackout. Clearly there should be an obligation on the part of the TOP and RC to monitor and mitigate these limits to prevent such propagation.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for Second Draft of SAR for Project 2007-03 — Real-time Transmission Operations and Balancing of Load and Generation

Please use this form to submit comments on the proposed SAR. Comments must be submitted by **September 7, 2007**. You may submit the completed form by e-mail to sarcomm@nerc.com with the words "Real-time TOP_BA SAR" in the subject line. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name: James Castle		
Organization: New York Independent System Operator		
Telephone: (518) - 356-6244		
E-mail: jcastle@nyiso.com		
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☒	2 — RTOs and ISOs
☐ **MRO**	☐	3 — Load-serving Entities
☒ **NPCC**	☐	4 — Transmission-dependent Utilities
☐ **RFC**	☐	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

Background Information:

The SAR for Real-time Transmission Operations and Balancing of Load and Generation (Project 2007-03) was posted for comment from May 15 through June 13, 200. The SAR Drafting Team considered the comments and corrected all noted typographical errors and made the following revisions to the SAR:

- Added IRO-004, IRO-005 & IRO-006 to the scope of standards to be reviewed to eliminate redundant requirements.

- Clarified that the reason for recommending the deletion of TOP-002-2, R8 is because the requirement is unmeasurable.

  R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.)

- Removed the recommendation for deleting TOP-002-2, R11:

  R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.

- Reworded the recommendation in TOP-002-2, R14 & R15 to clarify that these requirements may be better addressed in other standards.

  R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

  R14.1. Changes in real output capabilities.

  R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

- Clarified the deletion requested in TOP-004-1, R1 is the reference to 'SOLs'

  R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

Please review the revised SAR and then answer the question on the following page. Please submit your comments by **September 7, 2007** to sarcomm@nerc.com with the words "Real-time TOP_BA SAR" in the subject line.

1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☐ Yes

   ☒ No

   Comments: Both IRO-006-3 and draft IRO-006-4 have the TOP listed in applicability section. However, neither actually has any requirement in the standard. They simply reference the TOP in the requirements.

   Because there is not the typical question regarding additional comments in the comment form, we will provide those here.

   R8 in TOP-002-2 should not be eliminated because it is not measurable. The standards drafting should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible deletion may be appropriate, but the industy, not the SAR drafting team, should not be making this determination.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Craig McLean
Organization:	Manitoba Hydro
Telephone:	204 487 5517
E-mail:	cmclean@hydro.mb.ca

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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☐ **FRCC**	☐	2 — RTOs and ISOs
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Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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- Clarified that the reason for recommending the deletion of TOP-002-2, R8 is because the requirement is unmeasurable.

  R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.)

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Please review the revised SAR and then answer the question on the following page. Please submit your comments by **September 7, 2007** to sarcomm@nerc.com with the words "Real-time TOP_BA SAR" in the subject line.

1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☒ Yes

   ☐ No

   Comments: Although it is not covered in this SAR's second draft we are assuming from your response to comments on the initial draft that Requirements will remain to ensure that SOLs will be monitored by the RC and TOP and that appropriate action will be taken when SOLs are exceeded. This we agree with.

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Group Comments (Complete this page if comments are from a group.)

Group Name: Midwest ISO Stakeholders

Lead Contact: Jason L. Marshall

Contact Organization: Midwest ISO

Contact Segment: 2

Contact Telephone: 317-249-5494

Contact E-mail: jmarshall@midwestiso.org

Additional Member Name	Additional Member Organization	Region*	Segment*
Jeanne Kurzynowski	Consumers Energy	RFC	3
Jim Cyrulewski	JDRJC Associates	RFC	8
Kris Manchur	Manitoba Hydro	MRO	1
Barb Kedrowski	We Energies	RFC	5

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1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☐ Yes

   ☒ No

   Comments: We are concerned that the SAR drafting team did not provide an opportunity to comment on their proposed resolution to the SOL issue identified in Question 2 of the previous draft's comment form. It appears that the drafting team did not adequately address the view expressed by the majority of the commenters. We draw this conclusion from the inconsistency in the determination of what is a consensus and what isn't. For example, the comment form shows that the SAR drafting team wrote: "The SAR drafting team appreciates that the industry is near consensus," in response to comments on Question 1. There were 13 yes votes in support, 6 no votes against and 4 abstentions. In response to question 7, the SAR drafting team wrote: "The consensus is that the industry agrees with the stated purpose of the SAR." There were 14 yes votes indicating support, nine no votes indicating disagreement and no abstentions. Question 2 asked if the commenter agreed that SOLs should be moved into guides or good utility practices. 13 commenters voted no, 6 voted yes and 7 abstained. Given that the drafting team found near consensus on question 1 and consensus on question 7, we question why the drafting team does not view the responses to question 2 as a consensus?

   We are further troubled by the drafting team's solution to this SOL issue. In the responses, the SAR DT proposes to retain requirements to be aware of SOLs and monitor system conditions related to SOLs. However, there is actually no scope changes that reflect this response in draft 2 of the SAR. Addtionally, the drafting team asked only one specific question in the comment form for draft 2. It is unusual to not add the general open ended question that allows the commenter to provide any additional comments. We find this unusual given that the drafting team chose the word propose in their response. Use of this word would tend to invite a response because one is not sure that the proposal is acceptable. If the drafting team had an expectation that the proposal may not be acceptable, why would they not ask if the proposal is acceptable in the comment form? We believe they should have asked specifically if the proposed solution would "bridge the divide" between the commenters and the drafting team. Clearly they are on opposite ends of a spectrum with the SOL issue and one would think it would be prudent to determine if the gap has been narrowed enough before moving on to the standards drafting phase.

   We also believe that the SAR DT did not follow the Reliability Standards Development Procedure. On page 16, under step 2 is the following paragraph:

   "The requester, assisted by the SAR drafting team if one is appointed, shall give prompt consideration to written views and objections of all participants. An effort to resolve all expressed objections shall be made and each objector shall be advised of the disposition of the objection and the reasons therefore."

   It would appear that the SAR DT did not fully resolve expressed objections with removal of SOL requirements and should continue working to do so.

   We also have the following specific issues with the SAR.

R8 in TOP-002-2 should not be eliminated because it is not measurable. The standards drafting team should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible, deletion would then be appropriate. The SAR drafting team should not be making this determination.

Because the SAR states that R14 and R15 in TOP-002-2 may be better addressed in other standards, we are concerned that the standards drafting team may delete these requirements under the assumption that another team will add them to another standard. This standard drafting team should not remove these requirements unless they simply are not needed for reliability or are added to another standard in conjunction with the deletion.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**		
Name:		
Organization:		
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NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name: MRO NERC Standards Review Subcomitee

Lead Contact: Eric Ruskamp

Contact Organization: MRO

Contact Segment: 10

Contact Telephone: 402-473-3387

Contact E-mail: eruskamp@les.com

Additional Member Name	Additional Member Organization	Region*	Segment*
Joe Knight	Great River Energy	MRO	
Terry Bilke	MISO	MRO	
Mike Brytowski	MRO	MRO	
David Rudolph	Basin Electric Power Cooperative	MRO	
Pamela Oreschnick	Xcel Energy	MRO	
Rober Coish	Manitoba Hydro	MRO	
Neal Balu	WPSR	MRO	
Carol Gerou	Minnesota Power	MRO	
Jim Haigh	WAPA	MRO	
Ken Goldsmith	ALTW	MRO	
Tom Mielnik	MEC	MRO	
27 additional MRO members	not named above	MRO	

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

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- Reworded the recommendation in TOP-002-2, R14 & R15 to clarify that these requirements may be better addressed in other standards.

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1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☒ Yes

   ☒ No

   Comments: If the SAR Drafting team feels that the Standard Drafting Team can handle three additional standards the MRO has no issue with including them in the scope.

   Additional comments:

   It has come to our attention that TOP-001-1 R3 is an exact duplicate of IRO-001-1 R8. Of theses two instances, it seems most appropriate to remove the Requirement in IRO-001-1 as that standard is focused on the responsibilities and authorities of the Reliability Coordinator. The MRO recommends either including this in the scope of this SAR or adding this comment to the future work of the IRO-001-1 standard.

   R8 in TOP-002-2 should not be eliminated because it is not measurable. The SDT should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible, deletion would then be appropriate. It would seem more appropriate for the SDT to make this determination rather than the SAR DT.

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   The MRO members are also confused on the SOL issue. In the Consideration of Comments to SAR 1 question #2, the SAR DT asked the if it would be appropriate to remove all requirements related to SOLs from the NERC Reliability Standards. 5 groups of commenters agreed with removing SOLs, 9 disagreed and 5 abstained. The SAR DT concluded that they would propose to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs, yet nothing was changed in the scope of this SAR to reflect that decision. It would have been advantageous to request comments on the new direction proposed by the SAR DT on SOLs as it was heavily commented on during the last round of comments.

   The MRO members are also confused on the SOL issue. In the Consideration of Comments to SAR 1 question #2, the SAR DT asked the if it would be appropriate to remove all requirements related to SOLs from the NERC Reliability Standards. 5 groups of commenters agreed with removing SOLs, 9 disagreed and 5 abstained. The SAR DT concluded that they would propose to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs, yet nothing was changed in the scope of this SAR to reflect that decision. It would have been advantageous to request comments on the new direction proposed by the SAR DT on SOLs as it was heavily commented on during the last round of comments. Also it appears that all SOL are not crated equal, see the discussion below discussing potential SOL issues.

To the extent that an SOL is truly local (i.e. radial load serving line), there is no need for the SOL requirements. However, there are SOLs that may not pose a transmission security problem but could impose a generation adequacy problem on another system if the equipment should become damaged. Imports into another system may then be reduced. Additionally, multiple SOLs occuring on a system may be a sign of an undetected IROL. Clearly there should be an obligation on the part of the TOP and RC to review the situation to rule it out.

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Individual Commenter Information **(Complete this page for comments from one organization or individual.)**	
Name:	Rick White
Organization:	Northeast Utilities
Telephone:	860-665-2572
E-mail:	whitefb@nu.com

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
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1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

   ☒ Yes

   ☐ No

   Comments: TOP-001-1 R7.3 Replacing "at the earliest time" with "without delay" is not appropriate, since the step covers "When time does not permit.........". With this change, if there were any delay, it would be a noncompliance.

   TOP-007-0 Rewording R2 to say act "without delay", in lieu of "as soon as possible" is not desirable. With this change, if there were any delay, it would be a noncompliance.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for Second Draft of SAR for Project 2007-03 — Real-time Transmission Operations and Balancing of Load and Generation

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	David L. Gladey	
Organization:	PPL Susquehanna	
Telephone:	610-774-7774	
E-mail:	dlgladey@pplweb.com	

NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☐ **ERCOT**	☐	1 — Transmission Owners
☐ **FRCC**	☐	2 — RTOs and ISOs
☐ **MRO**	☒	3 — Load-serving Entities
☐ **NPCC**	☐	4 — Transmission-dependent Utilities
☒ **RFC**	☒	5 — Electric Generators
☐ **SERC**	☐	6 — Electricity Brokers, Aggregators, and Marketers
☐ **SPP**	☐	7 — Large Electricity End Users
☐ **WECC**	☐	8 — Small Electricity End Users
☐ **NA – Not Applicable**	☐	9 — Federal, State, Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

*If more than one Region or Segment applies, please list all that apply. Regional acronyms and segment numbers are shown on prior page.

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- Added IRO-004, IRO-005 & IRO-006 to the scope of standards to be reviewed to eliminate redundant requirements.

- Clarified that the reason for recommending the deletion of TOP-002-2, R8 is because the requirement is unmeasurable.

  R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.)

- Removed the recommendation for deleting TOP-002-2, R11:

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- Reworded the recommendation in TOP-002-2, R14 & R15 to clarify that these requirements may be better addressed in other standards.

  R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

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   ☒ Yes

   ☐ No

   Comments: IRO-004-1 is applicable to Generator Owners, currently the SAR only list the generator operators. The reliability functions listed in the SAR should be revised to include Generator Owner.

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Organization:		
Telephone:		
E-mail:		
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Group Comments (Complete this page if comments are from a group.)

Group Name: Public Service Commission of South Carolina

Lead Contact: **Phil Riley**

Contact Organization: **Public Service Commission of South Carolina**

Contact Segment: **9**

Contact Telephone: **803-896-5154**

Contact E-mail: **philip.riley@psc.sc.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Mignon L. Clyburn	Public Service Commission of SC	SERC	9
Elizabeth B. "Lib" Fleming	Public Service Commission of SC	SERC	9
G. O'Neal Hamilton	Public Service Commission of SC	SERC	9
John E. "Butch" Howard	Public Service Commission of SC	SERC	9
Randy Mitchell	Public Service Commission of SC	SERC	9
C. Robert "Bob" Moseley	Public Service Commission of SC	SERC	9
David A. Wright	Public Service Commission of SC	SERC	9

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   Comments:

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Individual Commenter Information (Complete this page for comments from one organization or individual.)		
Name:	Thomas J. Bradish	
Organization:	Reliant Energy	
Telephone:	724-597-8593	
E-mail:	tbradish@reliant.com	
NERC Region (check all Regions in which your company operates)		**Registered Ballot Body Segment (check all industry segments in which your company is registered)**
☒ **ERCOT**	☐	1 — Transmission Owners
☒ **FRCC**	☐	2 — RTOs and ISOs
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	☐	10 — Regional Reliability Organizations and Regional Entities

Group Comments (Complete this page if comments are from a group.)

Group Name:

Lead Contact:

Contact Organization:

Contact Segment:

Contact Telephone:

Contact E-mail:

Additional Member Name	Additional Member Organization	Region*	Segment*

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   ☒ Yes

   ☐ No

   Comments: In IRO-004-1 Reliability Coodination Operations Planning section 4.6 Generator Owners should be deleted. This standard is also applicable to generator operators as listed in 4.7. The justification for deleting GO is that this reliability standard addresses the operation of a generating facility. The GOP and not the GO would be the entity most knowledgable of equipment capabilities and ratings. The GOP would be the entity conducting and supervising any testing or unit operation required to comply with this standard. The GOP is most likely the entity responsible for maintenance of unit equipment so the GOP would be most familiar with equipment limits, ratings and capabilities. In addition, replacing GO with GOP in this standard and other standards has the following benefits:

   1. How a facility is operated has more impact on reliability than ownership of a facility.
   2. Removing the GO from responsibility will more clearly define who is responsible for standard compliance at jointly-owned facilities.
   3. For jointly-owned facilities, this change eliminates the need for each owner to make redundant submittals and streamlines administration for each Regional Entity.
   4. As the industry moves away from the regulated model, more non-traditional entities will become owners of facilities. These owners typically contract operation responsibilities to entities with operating experience. The operating entity will more fully understand the importance of reliability and would be in a better position to comply.
   5. Requiring the GO to be responsible for standard compliance may in some cases discourage non-traditional entities from owning generating assets, which will hinder competition in the market.

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Group Comments (Complete this page if comments are from a group.)

Group Name: Southern Company

Lead Contact: **JT Wood**

Contact Organization: **Southern Company Services**

Contact Segment:

Contact Telephone: **205-257-6238**

Contact E-mail: **jtwood@southernco.com**

Additional Member Name	Additional Member Organization	Region*	Segment*
Marc Butts	Southern Company Services	SERC	1
Jim Busbin	Southern Company Services	SERC	1
Roman Carter	Southern Company Services	SERC	1

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   ☒ Yes

   ☐ No

   Comments: To keep consistency and development among the related standards these standards should be taken into account in the review.

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Group Comments (Complete this page if comments are from a group.)

Group Name: WECC Reliability Coordination Comments Work Group

Lead Contact: **Nancy Bellows**

Contact Organization: **WACM**

Contact Segment: **10**

Contact Telephone: **970-461-7246**

Contact E-mail: **bellows@wapa.gov**

Additional Member Name	Additional Member Organization	Region*	Segment*
Paul Bleuss	CMRC	WECC	1
Mike Gentry	SRP	WECC	1
Greg Tillitson	CMRC	WECC	1

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   ☐ No

   Comments:

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on 2nd Draft of SAR for Real-time Transmission Operations and Balancing of Load and Generation (Project 2007-03)

The Real-time Transmission Operations and Balancing of Load and Generation SAR requesters thank all commenters who submitted comments on the first draft of SAR. This SAR was posted for a 30-day public comment period from August 7, 2007 through September 7, 2007. The requesters asked stakeholders to provide feedback on the SAR through a special SAR Comment Form. There were 15 sets of comments, including comments from 46 different people from 30 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, several minor changes were made to the SAR:

- A definitive statement was added to the SAR to clarify that the intent and scope of the SAR was not to remove requirements to monitor and be aware of SOLs.
- As suggested, Generator Owner was added to the list of applicable entities.
- For TOP-002-2: R7, R9, and R12 are no longer marked for possible deletion.
- In COM-002-2, a typo was corrected to point out that the correct reference is to PER-003-1 and not PER-003-0.

The SAR DT feels that these changes are not of a magnitude to require the re-posting of the SAR and is recommending that the SAR be forwarded to the Standards Committee for approval to move on to the standards development process.

It should be noted that there have been opinions expressed that more clarity is needed around SOLs – What are they? Who is responsible? Are they needed at all? While there are commenters who want this SAR DT to address those concerns, this SAR DT stands on its original goal, to remove oversights and problems caused by Version 0, et al. and to revise the resultant set of requirements with respect to the directives in FERC Order 693 and the latest Standard Review Guidelines.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Real-time_Operations_Project_2007-03.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Thad K. Ness	American Electric Power (AEP)	✓				✓	✓				
2.	Jason Shaver	American Transmission Co.	✓									
3.	Paul Bleuss (G3)	CMRC										✓
4.	Greg Tillitson (G3)	CMRC										
5.	Jeanne Kurzynowski (G1)	Consumers Energy			✓	✓						✓
6.	Ed Davis	Entergy Services						✓				
7.	Sam Ciccone	FE FERC Compliance Dept.	✓		✓		✓	✓				
8.	Doug Hohlbaugh	FE FERC Compliance Dept.	✓		✓		✓	✓				
9.	David Folk	FirstEnergy Corp. (FE)	✓		✓		✓	✓				
10.	Roger Champagne	Hydro-Québec TransÉnergie	✓									
11.	Ron Falsetti	IESO		✓								
12.	Kathleen Goodman	ISO New England		✓								
13.	Jim Cyrulewski (G1)	JDRJC Associates								✓		
14.	Eric Ruskamp (G5)	MRO										✓
15.	Joe Knight (G5)	Great River Energy										
16.	Terry Bilke (G5)	MISO										
17.	Mike Brytowski (G5)	MRO										
18.	David Rudolph (G5)	Basin Electric										
19.	Pamela Oreschnick (G5)	Xcel Energy										
20.	Robert Coish (G5)	Manitoba Hydro										
21.	Neal Balu (G5)	WPSR										
22.	Carol Gerou (G5)	Minnesota Power										
23.	Jim Haigh (G5)	WPSA										
24.	Ken Goldsmith (G5)	ALTW										
25.	Tom Mielnik (G5)	MEC										
26.	Craig McLean	Manitoba Hydro	✓		✓		✓	✓				

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
27.	Chris Manchur (G1)	Manitoba Hydro	✓									
28.	Jason L. Marshall (G1)	Midwest ISO Stakeholders		✓								
29.	Rick White	Northeast Utilities	✓									
30.	David L. Gladey	PPL Susquehanna			✓		✓					
31.	Phil Riley (G2)	PSC of SC									✓	
32.	Mignon L. Clyburn (G2)	PSC of SC									✓	
33.	Elizabeth Fleming (G2)	PSC of SC									✓	
34.	G. O'Neal Hamilton (G2)	PSC of SC									✓	
35.	John E. Howard (G2)	PSC of SC									✓	
36.	Randy Mitchell (G2)	PSC of SC									✓	
37.	Robert Moseley (G2)	PSC of SC									✓	
38.	David A. Wright (G2)	PSC of SC									✓	
39.	Thomas J. Bradish	Reliant Energy			✓		✓	✓				
40.	Mike Gentry (G3)	Salt River Project										✓
41.	Marc Butts (G4)	Southern Company Services	✓									
42.	Roman Carter (G4)	Southern Company Services	✓									
43.	Jim Busbin (G4)	Southern Company Services	✓									
44.	J. T. Wood (G4)	Southern Company Services	✓									
45.	Nancy Bellows (G3)	WACM										✓
46.	Barbara Kedrowski (G1)	We Energies					✓					

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – Midwest ISO Stakeholders
G2 – Public Service Commission of South Carolina (PSC SC)
G3 – WECC Reliability Coordination Comments Work Group
G4 – Southern Company Services, Inc. (SOCO)
G5 – Midwest Reliability Organization (MRO)

Index to Questions, Comments, and Responses

1. Do you agree to expand the scope of the SAR to include IRO-004, -005, & -006 for the purpose of eliminating redundancy related to the Transmission Operator and Balancing Authority?

Summary Consideration:

The consensus (12 submissions, 65 persons, 21 companies, 31 industry segment representations vs. 5 submissions, 9 persons, 9 companies and 10 industry segment representations) agreed that the scope of the SAR should be expanded to include the three subject IRO standards.

The primary concern voiced in this comment submittal was with the issue of SOLs. It is noted that the SOL issue is not what this SAR was about. This SAR was issued to clarify issues from Version 0, from the ERO regulatory agencies and other cited comments – and to improve the overall quality of the resultant set of requirements and standards.

The current SAR DT is composed of industry experts with long experience regarding the various NERC efforts to attempt to clearly define system limits. However, the current SAR DT does not claim to possess comprehensive knowledge of all of the issues related to SOL issues. We believe that the SOL issue must be addressed directly in a specific SAR effort formed to address it with a larger multi-disciplinary group.

It is clear that more clarity is needed around SOLs – What are they? Who is responsible? Are they needed at all? While there are commenters who want this SAR DT to address those concerns, this SAR DT stands on its original goal, to remove oversights and problems caused by Version 0, et al.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Manitoba Hydro	☑		Although it is not covered in this SAR's second draft we are assuming from your response to comments on the initial draft that Requirements will remain to ensure that SOLs will be monitored by the RC and TOP and that appropriate action will be taken when SOLs are exceeded. This we agree with.
Manitoba supports expanding the scope. **Response:** Unless changed in the Standards process, IRO-005 R2 would still require that SOLs be monitored; and IRO-005 R17 would still require that SOL violations be corrected. The SAR DT defines a scope, it can not and does not ensure that a given requirement remains or is deleted. The best the SAR DT can ensure is that an issue in its scope has the opportunity to be addressed.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Northeast Utilities	☑		TOP-001-1 R7.3 Replacing "at the earliest time" with "without delay" is not appropriate, since the step covers "When time does not permit.........". With this change, if there were any delay, it would be a noncompliance. TOP-007-0 Rewording R2 to say act "without delay", in lieu of "as soon as possible" is not desirable. With this change, if there were any delay, it would be a noncompliance.
NE Utilities supports expanding the scope of the SAR. **Response:** This wording should be discussed during the standards process. TOP-001-1 is an exclusion from the prohibition on 'blindly' removing facilities from service. The proposal to change the phraseology is suggested to address the issue that the current requirement allows too much leeway in informing the RC of what was done. TOP-007-0 does require a TOP to act to correct an IROL, and if the TOP does not act - then it is in non-compliance with the standard. The issue raised by the comment has been previously debated. "As soon as possible" was considered too subjective, whereas "without delay" was considered less subjective. The real question is what constitutes "action". The time associated with evaluating the system is considered (by the writers of the proposal) to be an action. The impetus behind the requirement is that each TOP already has its list of IROL response procedures, and therefore (unless there is a real good reason) the TOP should be implementing those procedures. The underlying 'evaluation action' is the time when reasoned adjustments to the plan is expected. One can debate how long the evaluation time should be, and even debate what is an evaluation but no one was able to come up with a standardized performance. It is left to the voters to decide if this is a problem and if it is how to fix the problem.			
PPL Susquehanna	☑		IRO-004-1 is applicable to Generator Owners, currently the SAR only list the generator operators. The reliability functions listed in the SAR should be revised to include Generator Owner.
PPL Susquehanna supports expanding the scope of the SAR. **Response:** Thank you, the SAR Applicability list will be so amended.			
Reliant Energy	☑		In IRO-004-1 Reliability Coodination Operations Planning section 4.6 Generator Owners should be deleted. This standard is also applicable to generator operators as listed in 4.7. The justification for deleting GO is that this reliability standard addresses the

Question #1			
Commenter	**Yes**	**No**	**Comment**
			operation of a generating facility. The GOP and not the GO would be the entity most knowledgable of equipment capabilities and ratings. The GOP would be the entity conducting and supervising any testing or unit operation required to comply with this standard. The GOP is most likely the entity responsible for maintenance of unit equipment so the GOP would be most familiar with equipment limits, ratings and capabilities. In addition, replacing GO with GOP in this standard and other standards has the following benefits: 1. How a facility is operated has more impact on reliability than ownership of a facility. 2. Removing the GO from responsibility will more clearly define who is responsible for standard compliance at jointly-owned facilities. 3. For jointly-owned facilities, this change eliminates the need for each owner to make redundant submittals and streamlines administration for each Regional Entity. 4. As the industry moves away from the regulated model, more non-traditional entities will become owners of facilities. These owners typically contract operation responsibilities to entities with operating experience. The operating entity will more fully understand the importance of reliability and would be in a better position to comply. 5. Requiring the GO to be responsible for standard compliance may in some cases discourage non-traditional entities from owning generating assets, which will hinder competition in the market.

Reliant supports expanding the scope of the SAR

Response:
The scope of this SAR with regard to IRO-004 is to simply eliminate redundancies within that standard for the TOP. We suggest that you should submit these comments to the SDT dealing with specific changes to the IRO requirements.

1. The line of reasoning for obligating an Owner for providing 'unit ratings' is as follows: The Owner has the inherent right (as the owner of the facility) to rate that facility in any way the owner sees fit. On the other hand, the Operator of the asset can be a third party that must respect the owner's boundaries and still work within the constraints of the BES. The Operator has the right / obligation to use the Owner's rating to stay within the reliability constraints of the BES. The Operator may further constrain a units operation, but should not (without the owner's permission) violate the Owner's imposed unit rating.

2. The asset belongs to the Owner, and the Owner's risk management should be respected.

3. This is a legal / contractual issue not a NERC issue.

Question #1			
Commenter	**Yes**	**No**	**Comment**
4. This is a legal / contractual issue not a NERC issue. 5. This is an opinion / projection that is outside NERC / the SAR DT concerns.			
American Electric Power	☑		We agree with the concept of eliminating redundancy in the NERC Standards. However, Project 2006-08 involves re-writing IRO-006 in three phases and is currently in phase one. Any changes required to IRO-006 to eliminate redundancy of Transmission Operator and Balancing Authority requirements in other standards should be coordinated with, and handed off to, the Project 2006-08 IRO-006 Standard Drafting Team. Thus, IRO-006 should not be included in the scope of this SAR. We have no objection to including IRO-004 and IRO-005 into the scope of this project and we stand by our comments to the first SAR.
AEP supports expanding the SAR for IRO-004 and 005. **Response:** IRO-006 The SAR DT recognizes that there is a need for coordination among different NERC Projects but it is the Standards DT that has the responsibility for coordinating any changes that the Industry approves, and to coordinate them with other Projects (in coordination with the NERC Standards Manager and the NERC Standards Committee). Project 2006-08 is designed to focus on the TLR process. The SAR DT is focused on responding to previous unanswered comments; and in identifying and eliminating redundancies.			
Entergy	☑		We have additional comments on other parts of this revised SAR. COMMENTS ON TOP-001-1 We suggest the deletion of the first recommended change to TOP-001-1: o Removal of R2 due to redundancy with R1. R2 largely describes an ill-defined procedure which should not be in a standard. This suggested change was revised from the first posting of this SAR, changing "with R3" to "with R1". Each of the three requirements of TOP-001-1 address different

Question #1			
Commenter	**Yes**	**No**	**Comment**
			responsibilities of a TOP. R1 states a TOP has responsibility and authority, R2 states the TOP will take action, and R3 states the TOP and others will comply with the directives of the RC, or TOP. We do not agree R2 contains an ill-defined procedure. However, we may agree to remove TOP-001-1 R2 because it may be redundant with TOP-008-1 R1. We also suggest revising the TOP-001-1 draft change from: - Eliminating R5 in light of possible redundancy with IROL standards. to: - Eliminating R5 IF REDUNDANT with IROL standards. COMMENTS ON TOP-002-2 The first suggestion of TOP-002-2 suggests deleting R1 as it is redundant with TOP-008-1 R1. We recommend changing the TOP-008-1 reference to R2, rather than R1. We agree that TOP-002-2 can be eliminated as being redundant with TOP-008-1 R2, not TOP-008-1 R1. We do not agree with the suggestion that TOP-002-2 that R4 should be deleted. TOP-002-2 R4 is a requirement on the BA and TOP while IRO-005-2 R9 is a requirement on the RC. We do not agree with the suggestion of deleting TOP-002-2 R6 as it is redundant with IRO-005-2 R9. However, we do agree with deleting R6 if the reason is changed to being redundant with EOP-001 R3.2. With this change we agree with deleting TOP-002-2 R6. We do not agree with the suggestion to delete TOP-002-2 R7 and R9. Both these requirements should remain in TOP-002. The reason for the suggested deletion is R7 and R9 are redundant with BAL-007 through BAL-011. However, BAL-007 through BAL-011 were not approved by the Ballot Body and are not NERC standards. Therefore TOP-002-2 R7 and R9 are not redundant and the suggestion should be deleted. TOP-002-2 R12 should not be deleted. We believe it is not redudant of the requirements in FAC-010 SOL Methodology for the Planning Horizon and FAC-011 SOL Methodology for the Operations Horizon.

Question #1			
Commenter	**Yes**	**No**	**Comment**
			COMMENTS ON TOP-004-1 The first entry for TOP-004-1 suggests deleting reference to SOL in R1. Deleting R1 indicates TOPs are not required to operate within SOLs. TOPs should operate within SOLs and this entry should be deleted from the SAR. COMMENTS ON TOP-005-1 It is suggested deleting R1 and R1.1 as they are redundant with IRO-010-1. However, IRO-010-1 is not an approved standard so R1 and R1.1 should remain in TOP-005-1. That is unless the SAR is changed to say R1 and R1.1 should be deleted after IRO-010-1 is approved and has provisions that duplicte R1 and R1.1. It is suggested that R4 be deleted from TOP-005-1. Do not delete R4 (PSE provides information as requested for reliability assessments and coordinate operations) as it is significantly more encompassing than INT-001-2 R1 (which only requires PSEs provide Arranged Interchange to the IA.) If anything is done INT-001-2 R1 should be deleted and TOP-005-1 R4 should be kept. COMMENTS ON TOP-006-1 It is suggested that R1 be deleted from TOP-006-1. Do not delete R1 (report facility status) as it is significantly different than FAC-009-1 R2 (report facility ratings). They are not the same. It is suggested that R4 be deleted from TOP-006-1 as the requriement is redundant with BAL-001 and -002 and is addressed in IRO-010 R1 and R3. R4 should only be deleted if the requirements are actually included in the final approved IRO-010. It is suggested that R6 (use sufficient metering) be deleted from TOP-006-1 as the requirement is redundant with BAL-005-1 (annually check and calibrate time error and frequency devices). We suggest R6 be kept in TOP-006-1 since the requirements are not in BAL-005-1. COMMENTS ON TOP-007-0

Question #1			
Commenter	**Yes**	**No**	**Comment**
			It is suggested to delete R4 in deference to the RC Project. We suggest R4 be kept in TOP-007-0 until the RC Project is a NERC approved standard. COMMENTS ON TOP-008-0 It is suggested to delete R1 (relieve IROL or SOL) as it is redundant with TOP-007-0 R3 (relieve IROL). We suggest R1 be kept in TOP-008-0 or include SOLs in TOP-007-0 R3. COMMENTS ON COM-001-1 No Comments. COMMENTS ON COM-002-2 The first bullet is to delete the second sentence of COM-002-2 R1 as it is redundant with PER-003-0 R3. However, there is no R3 in PER-003-0 so we recommend the second sentence stay in COM-002-2 R1.

Entergy agrees with expanding the scope of the SAR.

Response:

1. **TOP-001-1**: Entergy and the DT both agree with the removal of **R2**; but Entergy disagrees with the rationale provided. The purpose of the SAR DT is to provide a scope for a Standard DT. The SAR DT's rationale is provided to help understand the DT's justification, the rationale is not provided for approval or inclusion in the standard. This reply also applies to the comment for **R5**. Entergy approves considering **R5** for removal, but does not agree with the justification. The words used in the request's justification are not under debate. The debate is whether or not to keep the item in scope.

2. **TOP-002-2**: Entergy and the DT both agree with the removal of **R1**; but Entergy disagrees with the rationale provided. The issue that must be resolved is whether or not it is sufficient that a NERC standard hold one entity responsible for coordinating a given task, or should every entity be assigned partial responsibility. This requirement is therefore included within scope and will best be debated in the Standards Development process.
   We both agree with the removal of **R6**; but Entergy disagrees with the rationale provided.

   You are correct that BAL-007 – 011 have not been approved and therefore R7 and R8 can not be held redundant.

Question #1			
Commenter	**Yes**	**No**	**Comment**

However, this does not remove TOP-002-2 from the scope of the SAR.

You are correct that R12 is not redundant with the FAC-010 & 011 standards. The elimination of this requirement does not materially affect the scope of the request, as TOP-002 will still remain in scope.

3. **TOP-004-1**: The commenter stated that removing R1 of TOP-004 will remove the obligation of TOPs from operating within SOLs. The SAR DT notes that IRO-005 R17 properly places the responsibility on the RC who in turn has the authority to require the TOP to act. The debate is best carried out by the Industry in the standards process not in the scoping phase. If the Industry agrees that the responsibility is on the RC and that a requirement on the TOPs is unnecessary then the requirements on the TOPs will be removed. If the Industry agrees that there is a separate need for TOPs to have a standard requirement on them, then the requirement will be retained. Either way there is a need for the issue to be discussed.

4. **TOP-005-1**: The commenter is correct that the observed redundancy for R1 and R1.1 is predicated on a non-approved standard. The SAR DT agrees that any Industry-approved changes should / must be coordinated with the other BOT-approved standards in place at the time the new modifications are to be implemented.

   The commenter is correct that TOP-005-1 R4 is more inclusive then INT-001-2 R1. The SAR DT's intent was to delete one of the two. The decision of which if any of the two requirements to retain, modify or delete is to be decided by the industry.

5. **TOP-006-1:** The commenter is correct that the data requirements of TOP-006-1 R1 (unit availability) is different from the data requirements of FAC-009-1 R2 (unit capability / rating).

   Regarding R4 the SAR DT agrees that any Industry-approved changes should / must be coordinated with the other BOT-approved standards in place at the time the new modifications are to be implemented.

   The commenter is correct that R6 (sufficient metering) is different from BAL-005-1 (calibration).

   TOP-007-0: Regarding R4, the SAR DT agrees with Entergy that any Industry-approved changes should / must be coordinated with the other BOT-approved standards in place at the time the new modifications are to be implemented.

6. **TOP-008-0:** The debate over SOL/IROL is best carried out by the Industry in the standards process not in the scoping phase. If the Industry agrees that the responsibility is on the RC and that a requirement on the TOPs is unnecessary then the requirements on the TOPs will be removed. If the Industry agrees that there is a separate need for TOPs to have a standard requirement on them, then the requirement will be retained. Either way there is a need for the issue to be

Question #1			
Commenter	**Yes**	**No**	**Comment**
			discussed. 7. The redundancy is between PER-003-1 (not PER-003-0) R3 and COM-002-2 R1.
FirstEnergy Corp.	☑		FirstEnergy, like some other entities, is concerned that the SAR drafting team did not provide an opportunity to comment on their proposed resolution to the SOL issue identified in Question 2 of the previous draft's comment form. While it is not crystal clear to us that the SAR Drafting Team intended to removal all references to SOLs from the Standards, it is also not clear to us that the revisions made to the SAR by the drafting team adequately addressed the views expressed by the commenters. The messages sent by the SAR Drafting Team in the Comment Summary and the individual responses to comments seem mixed. The response to comments document indicates that the SAR drafting team will pass comments on to the Standard Drafting Team; however, the modifications to the SAR were minor and did not provide any guideance to the Standard Drafting Team on the method for applying these comments. Furthermore, the SAR Drafting Team did not seem to embrace the comments provided by the industry on this topic. We understand that the comments received were provided by a small segment of the industry; however, we are also aware that the communication from the commenters was was clear. The majority of commenters supported the retention of SOLs in the standards as necessary and appropriate. All of this being said, while we clearly do not agree with the wholesale removal of SOLs from the Standards, but we do support the removal of SOLs from TOP-004-1 Requirement 1 as specified in the SAR. We support this because the methodology used to determine SOLs, and for that matter, IROLs is not clearly defined. This means that one organization may be using a methodology that produces an eight hour SOL while another's method may produce a one hour SOL. We believe that the company using an eight hour limit should not be bound as tightly to that limit as a company that uses a one hour limit. Therefore, the SAR should direct the Standard Drafting team to develop, or at least investigate the development, of a limit methodology applicable across all of NERC that can be consistently applied. FE also offers the following comments to specific items revised in the SAR: Added IRO-004, IRO-005 & IRO-006 to the scope of the standards to be reviewed to eliminate redundant requirements. FE agrees

Question #1			
Commenter	**Yes**	**No**	**Comment**
			Clarified that the reason for recommending the deletion of TOP-002-2, R8 is because the requirement is unmeasurable. R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency. FE disagrees with this direction. There does not appear to be an industry agreed upon justification given to remove this requirement in lieu of developing 'R8' along with eliminating ambiguity in the existing measure for this requirement described in 'M3'. Removed the recommendation for deleting TOP-002-2, R11: R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator. FE agrees Reworded the recommendation in TOP-002-2, R14 & R15 to clarify that these requirements may be better addressed in other standards. R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but no limited to: R14.1. Changes in real output capabilities R15. Generator Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output). FE agrees, but with the following provision: The SDT should also develop clear justification for addressing these requirements in "other standards" while identifying the appropriate "other standards"; and, if justified, the SDT should develop a clear, industry approved plan to transfer these requirements to those identified standards.

<table>
<tr><th colspan="4">Question #1</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>Clarified the deletion requested in TOP-004-1, R1 is the reference to 'SOLs'
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
FE agrees, but with the following provision:

The SDT should also consider verbiage in the standards with regard to how SOLs can still be conveyed with some indirect measure (non-sanctioned) of importance in development of the applicable standards.</td></tr>
<tr><td colspan="4">FE agrees that IRO-004, 005 and 006 should be included in the scope of the SAR to eliminate redundancies

Response:
TOP-002-2
The debate regarding the removal of given requirements will be part of the standards development process (not the SAR process). The direction and philosophy of the Industry will be decided by the comments and responses to the standards. The Industry will decide whether or not to retain TOP-002-2 R8. The comments and responses will decide whether or not the measures associated with are appropriate. The question is whether or not to have the debate, and your response shows that there is such a need.

The SAR DT recognizes the need for coordination among standards. However, the SAR DT has the responsibility for defining the scope, it does not have the responsibility or the power to develop an implementation scheme for changes that have not yet been identified let alone approved. It is the Standards DT responsibility to coordinate the implementation of any changes that the industry approves during the standards development phase of the process.

TOP-004-1
The issue of SOL definition and requirements will be dictated by what requirements and standards are approved by the Industry.</td></tr>
<tr><td>PS Commission of South Carolina</td><td>☑</td><td></td><td></td></tr>
<tr><td>Southern Company</td><td>☑</td><td></td><td></td></tr>
<tr><td>WECC Reliability Coordination Comments Work</td><td>☑</td><td></td><td></td></tr>
</table>

Question #1			
Commenter	**Yes**	**No**	**Comment**
Group			
Response: The RTO SAR DT thanks you for your support.			
IESO	☑	☑	Since this comment form has only one question, we are checking both boxes - yes for inclusion of IRO-004, -005 and -006 but no to some of the changes made or not made to the previous SAR, and provide additional comments as follows: (1) Specific to the bullets provided in the background section, above, we agree with the first bullet and do not have any comments on the 2nd to 4th bullets. However, we do not agree with the 5th bullet to remove reference to SOL from TOP-004-1 R1, which requires that "Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs)." In the SAR DT's response posted in Consideration of Comments, it states that "Based on stakeholder comments, the SAR DT is proposing to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs." Removing reference to SOL in TOP-004-1 R1 contradicts with the above statement. Further, we continue to strongly disagree with the SDT that TOPs are not required to operate within SOLs - We agree that all SOLs are not created equally but there are those SOLs which have a tremendous impact on system reliability, much in the same way as IROLs, and given the appropriate conditions, these very SOLs, if not complied with, could have a highly detrimental impact on the system and subsequntly the interconnection (also see comments by others in the Consideration of Comments). (2) In the Consideration for Comments, the SAR DT responded to our previous comments under Question #9, from TOP-001 R2 to TOP-002 R18. We appreciate that the DT's concurs with most of our comments. However, we are unable to find the DT's response to our other comments, from TOP-003 to TOP-008. A review of the revised SAR indicates that changes proposed in the previous SAR for these standards/requirements would remain, some of which we expressed disagreement in our previous comment submission. Not seeing a response from the SAR DT, we are uncertain whether our comments were overlooked, or the DT concluded that our comments did not result in any material changes to the proposed revisions to these

Question #1			
Commenter	Yes	No	Comment
			standards. Assuming it was an oversight, we are providing our comments on TOP-003 to TOP-008 again as follows. We would appreciate seeing the DT's response to these comments when the Consideration of Comments on this revised SAR is posted. TOP-003-0 R3: the SDT suggests deleting R1.3 as it is redundant with IRO-010, R3 as part of the over-all data specification effort. We believe the referenced requirement should be R4. TOP-004-0 R1: the SDT suggests deleting R1 as it is redundant with IRO-009-1, R4. We disagree with this. SAR IRO-009-1 holds the RC responsible for operated within IROL. We feel strongly that the TOP must also operate its system to respect IROL. Further, we need to defer any changes to remove or modify SOL until after the definition of Adequate Level of reliability is defined. We also provided other reasons for retaining it. Please see our comments on Q2, above. R2: the SDT suggests deleting R2 as it is simply the definition of an IROL and is redundant with FAC-010-1 and FAC-011-1. We disagree with this proposal since R2 requires TOP to operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. FAC-010-1 and FAC-011-1 deal with the methodology to determine SOL and IROL. They hold different entities for doing very different things altogether. R3: We disagree with removing this requirement for the above same reason. TOP-005-1 R2: the SDT suggests deleting this requirement. We agree that R2 is not a reliability requirement, but the SDT needs to recommend a home for entities that receive data from the ISN that it must sign the NERC Confidentiality Agreement for “Electric System Reliability Data".

Question #1			
Commenter	**Yes**	**No**	**Comment**
			TOP-006-1 R1: the SDT suggests deleting R1 as it is redundant with FAC-009-1, R2. We disagree with this proposal since R1 deals with real-time data such as facility status, resource availability; whereas FAC-009-1 deals with establishing ratings. R4: the SDT suggests deleting R4 as it is redundant with BAL-001 and -002 and is also addressed in IRO-010-1, R1 and R3. We disagree as R4 requires the operating entities to do things that are very different from any of BAL-001, BAL-002 and IRO-010-1. R7: the SDT considers deleting Balancing Authority as it is covered in BAL-005-0, R8 and deleting Reliability Coordinator as it is covered in BAL-008-1, R1. We do not agree with both. In the first case, the requirements for the BA in R7 is to monitor system frequency which is different than those in BAL-005-0, R8 which specify the data and metering requirements. In the second case, BAL-008 doesn't yet exist (failed ballot). TOP-008 R3: the SDT suggests deleting R3 as it is a local utility risk consideration and not a reliability issue as currently worded. We do not agree with the deletion since the requirement implies that the action taken by the TOP has interconnected system implication.

IESO supports expanding the scope of the SAR.

Response:

The IESO requests a comprehensive debate on SOLs, and that requires an independent SAR. The proposal to change TOP-004 would eliminate the immediate conflict and allow NERC to have a standard that all entities agree with (i.e. everyone agrees that TOPs should operate within IROLs.) while leaving the debate on SOLs for another SAR. As such the decision would be made by the voters and not by the SAR DT. The concern among some is with the fact that System Operating Limits are not “in every case” adhered to (or needed to be adhered to) – as IESO notes in its comments “not all SOLs are created equal.” TOPs often make use of multiple System Operating limits (instantaneous, short term and longer term limits). Exceeding a given limit while respecting a shorter time limit is an everyday occurrence. When is the TOP non-compliant? To which value? IROLs on the other hand are not viewed in the standards in the same way as SOLs. The IROL standards go as far as to require proactive operations before the limit is violated.

Question #1			
Commenter	**Yes**	**No**	**Comment**

The SAR DT did not see a contradiction in retaining requirements to monitor SOLs because although it is not uncommon to exceed some SOLs, it is still important to know what is happening on the system. By leaving the monitoring to RCs, the standards ensure that someone is watching out for 'reliability' but not necessarily for a precise limit compliance. RCs must be aware of those SOLs that do "have a tremendous impact". But unless and until there is a better definition of SOL, it will be impossible to separate which SOLs require compliance and which SOLs do not.

TOP-003-0
IRO-010-1 (dated March 8, 2007) does not have an R4. The SDT reference to R3 (which states that everyone must provide data to the RC) is a good replacement for the prescriptive TOP-003-0 R1.3 (which fixes times of day). Indeed one could argue that such timing requirements belong to NAESB not NERC.

The SAR DT does recognize that IRO-010-1 has not been approved. Therefore the Standards DT must consider that any Industry-approved changes should / must be coordinated with the other BOT-approved standards in place at the time the new modifications are to be implemented.

TOP-004-0
The SAR DT interprets R1 (having the RC and TOP both responsible for the same IROL) as redundant and suggests that the Industry consider formalizing the requestor's view. IESO asks that this debate not be raised. The SAR DT believes that it should be discussed. The SAR DT merely keeps this issue in its scope; the voters will decide the merit of that view.

R2 follows the same logic as R1. The SAR DT believes that the issue of whether or not RC and TOP having identical responsibilities is redundant is an issue that they want in their SAR.

R3 – The debate between RC and TOP not withstanding, this requirement must be kept within scope, if for no other reason then the fact that both FERC and NERC require removal of all references to RRO.

TOP-005-1
The SAR DT is not responsible for finding a home for the ISN. IESO agrees that the current requirement "is not a reliability requirement". IESO has not provided any justification for its position that the SAR DT has that obligation.

TOP-006-1
IESO is correct that the data requirements of TOP-006-1 R1 (unit availability) are different from the data requirements of FAC-009-1 R2 (unit capability / rating).

Contrary to the IESO statement, R4 requires does not require operating entities to do anything; R4 requires them to have

Question #1			
Commenter	**Yes**	**No**	**Comment**
data to predict "near-term load patterns". The SAR DT original comment was based on the concept that the real objective of load forecasting is system control. Hence whether or not an entity has data, the BAL standards require them to control the system. Of course near-term load forecasting is used in other areas of operation (e.g. unit commitment); the fact is that R4 is considered by some as being meaningless as a standard. As long as the entities have access to the internet they will have information to predict load. R7: The SAR DT does recognize that BAL-008 & 009 were not approved, but is also aware that they are under active reconsideration. R7 requires monitoring of frequency. The issue of redundancy arises from the fact that BA-005 requires BA have the information to compute ACE, and by definition ACE includes frequency, ergo, the BA is for all practical purposes monitoring frequency. Even if BAL-008 doesn't pass again, the RC is responsible for reliability (real power, reactive power, voltage and frequency). It makes no sense to have a standard for each item that must be monitored. Common sense must be applied to the standards. **TOP-008** See first two paragraphs of Response.			
MRO	☑	☑	If the SAR Drafting team feels that the Standard Drafting Team can handle three additional standards the MRO has no issue with including them in the scope. Additional comments: It has come to our attention that TOP-001-1 R3 is an exact duplicate of IRO-001-1 R8. Of theses two instances, it seems most appropriate to remove the Requirement in IRO-001-1 as that standard is focused on the responsibilities and authorities of the Reliability Coordinator. The MRO recommends either including this in the scope of this SAR or adding this comment to the future work of the IRO-001-1 standard. R8 in TOP-002-2 should not be eliminated because it is not measurable. The SDT should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible, deletion would then be appropriate. It would seem more appropriate for the SDT to make this determination rather than the SAR DT. Because the SAR states that R14 and R15 in TOP-002-2 may be better addressed in

Question #1			
Commenter	**Yes**	**No**	**Comment**
			other standards, we are concerned that the standards drafting team may delete these requirements under the assumption that another team will add them to another standard. This standard drafting team should not remove these requirements unless they simply are not needed for reliability or are added to another standard in conjunction with the deletion. The MRO members are also confused on the SOL issue. In the Consideration of Comments to SAR 1 question #2, the SAR DT asked the if it would be appropriate to remove all requirements related to SOLs from the NERC Reliability Standards. 5 groups of commenters agreed with removing SOLs, 9 disagreed and 5 abstained. The SAR DT concluded that they would propose to retain requirements to (1) be aware of SOLs and (2) monitor system conditions related to SOLs, yet nothing was changed in the scope of this SAR to reflect that decision. It would have been advantageous to request comments on the new direction proposed by the SAR DT on SOLs as it was heavily commented on during the last round of comments. Also it appears that all SOL are not crated equal, see the discussion below discussing potential SOL issues. To the extent that an SOL is truly local (i.e. radial load serving line), there is no need for the SOL requirements. However, there are SOLs that may not pose a transmission security problem but could impose a generation adequacy problem on another system if the equipment should become damaged. Imports into another system may then be reduced. Additionally, multiple SOLs occuring on a system may be a sign of an undetected IROL. Clearly there should be an obligation on the part of the TOP and RC to review the situation to rule it out.
MRO supports expanding the scope of the SAR. **Response:** Both TOP-001 and TOP-002 are included in the scope of this SAR, and MRO will have the opportunity to be involved in what is or isn't included in those standard. Regarding the issue of SOLs, the SAR DT did not and does not intend to include a complete discussion of all the issues that must be debated on that topic. The SAR DT agrees with MRO that not all SOLs are created equal, and that is the reason the DT is proposing within this Project to, as much as possible, focus on IROLs. To eliminate confusion, MRO may desire to submit its own SAR regarding how to address SOLs.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
ISO New England **NY ISO**		☑	Both IRO-006-3 and draft IRO-006-4 have the TOP listed in applicability section. However, neither actually has any requirement in the standard. They simply reference the TOP in the requirements. Because there is not the typical question regarding additional comments in the comment form, we will provide those here. R8 in TOP-002-2 should not be eliminated because it is not measurable. The standards drafting should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible deletion may be appropriate, but the industy, not the SAR drafting team, should not be making this determination. Because the SAR states that R14 and R15 in TOP-002-2 may be better addressed in other standards, we are concerned that the standards drafting team may delete these requirements under the assumption that another team will add them to another standard. This standard drafting team should not remove these requirements unless they simply are not needed for reliability or added to another standard in conjunction with the deletion. The SAR drafting team should modify the scope so that all requirements to monitor and control flows within SOLs are not eliminated. While the SAR drafting team points out in their response to the comments that NERC's definition defines an SOL as local, eliminating all requirements to monitor and control to SOLs will be detrimental to reliability. Multiple SOLs occuring on a system may be a sign of an undetected IROL or, if left unchecked, propagate into an IROL. This was the cause of the August 14th blackout. Clearly there should be an obligation on the part of the TOP and RC to monitor and mitigate these limits to prevent such propagation.
ISO NE & NYISO do not support expansion of the scope of the SAR. **Response:** **IRO-006** The commenter is correct that the TOP is not in IRO-006. **TOP-002-2** The debate regarding the removal of given requirements will be part of the standards development process. The direction and			

Question #1			
Commenter	**Yes**	**No**	**Comment**
philosophy of the Industry will be decided by the comments and responses to the standards. The Industry will decide whether or not to retain TOP-002-2 **R8**. The comments and responses will decide whether or not the measures associated with are appropriate. The question posed by the DT is whether or not to have the debate, and your comments show that there is such a need. Regarding R14 and R15, the SAR DT does not add or remove anything; and in fact the Standards Drafting Team does not add or remove anything. The voters decide what gets included and what gets excluded. The SAR DT has proposed a scope of standards to be addressed for the purpose of eliminating redundancies and removing non-standards. The voters decide which standards / requirements get modified or changed. **SOLs** The issue of whether or not there is a need for a standard that SOLs should be monitored is proposed. If the voters agree they will eliminate the requirement and if they want to keep it they will retain the requirements. The SAR DT wants to have the debate whether or not NY and NE agree, SARs are scoping documents designed to request changes. Once approved the SAR is the starting point for debates on issues identified by the SAR drafter. NY and NE must participate in the standards process to make their point, rather than avoid the impending required debate.			
MISO Stakeholders		☑	We are concerned that the SAR drafting team did not provide an opportunity to comment on their proposed resolution to the SOL issue identified in Question 2 of the previous draft's comment form. It appears that the drafting team did not adequately address the view expressed by the majority of the commenters. We draw this conclusion from the inconsistency in the determination of what is a consensus and what isn't. For example, the comment form shows that the SAR drafting team wrote: "The SAR drafting team appreciates that the industry is near consensus," in response to comments on Question 1. There were 13 yes votes in support, 6 no votes against and 4 abstentions. In response to question 7, the SAR drafting team wrote: "The consensus is that the industry agrees with the stated purpose of the SAR." There were 14 yes votes indicating support, nine no votes indicating disagreement and no abstentions. Question 2 asked if the commenter agreed that SOLs should be moved into guides or good utility practices. 13 commenters voted no, 6 voted yes and 7 abstained. Given that the drafting team found near consensus on question 1 and consensus on question 7, we question why the drafting team does not view the responses to question 2 as a consensus? We are further troubled by the drafting team's solution to this SOL issue. In the responses, the SAR DT proposes to retain requirements to be aware of SOLs and monitor system conditions related to SOLs. However, there is actually no scope changes that

Question #1			
Commenter	**Yes**	**No**	**Comment**
			reflect this response in draft 2 of the SAR. Addtionally, the drafting team asked only one specific question in the comment form for draft 2. It is unusual to not add the general open ended question that allows the commenter to provide any additional comments. We find this unusual given that the drafting team chose the word propose in their response. Use of this word would tend to invite a response because one is not sure that the proposal is acceptable. If the drafting team had an expectation that the proposal may not be acceptable, why would they not ask if the proposal is acceptable in the comment form? We believe they should have asked specifically if the proposed solution would "bridge the divide" between the commenters and the drafting team. Clearly they are on opposite ends of a spectrum with the SOL issue and one would think it would be prudent to determine if the gap has been narrowed enough before moving on to the standards drafting phase. We also believe that the SAR DT did not follow the Reliability Standards Development Procedure. On page 16, under step 2 is the following paragraph: "The requester, assisted by the SAR drafting team if one is appointed, shall give prompt consideration to written views and objections of all participants. An effort to resolve all expressed objections shall be made and each objector shall be advised of the disposition of the objection and the reasons therefore." It would appear that the SAR DT did not fully resolve expressed objections with removal of SOL requirements and should continue working to do so. We also have the following specific issues with the SAR. R8 in TOP-002-2 should not be eliminated because it is not measurable. The standards drafting team should attempt to modify it so that there is a requirement on maintaining voltage or reactive levels that is measurable. If this is not possible, deletion would then be appropriate. The SAR drafting team should not be making this determination. Because the SAR states that R14 and R15 in TOP-002-2 may be better addressed in other standards, we are concerned that the standards drafting team may delete these requirements under the assumption that another team will add them to another standard. This standard drafting team should not remove these requirements unless

Question #1			
Commenter	**Yes**	**No**	**Comment**
			they simply are not needed for reliability or are added to another standard in conjunction with the deletion. The SAR drafting team should modify the scope so that all requirements to monitor and control flows within SOLs are not eliminated. While the SAR drafting team points out in their response to the comments that NERC's definition defines an SOL as local, eliminating all requirements to monitor and control to SOLs will be detrimental to reliability. To the extent that an SOL is truly local (i.e. radial load serving line), there is no need for this requirement. However, there are SOLs that may not pose a transmission security problem but could impose a generation adequacy problem on another system if the equipment should become damaged. Imports into another system may then be reduced. Additionally, multiple SOLs occuring on a system may be a sign of an undetected IROL. Clearly there should be an obligation on the part of the TOP and RC to review the situation to rule it out.

MISO does not support expanding the scope of the SAR.

Response:

If MISO Stakeholders believes that there was a blatant disregard for the process they can file a complaint with the NERC Standards Committee.

MISO Stakeholders should not be troubled by the SAR DT's "solution" to the SOL issue, because the SAR DT did not provide a solution – they provided a scope of work to address prior industry questions to reduce / eliminate redundancies. If MISO Stakeholders would like to propose SOL standards, again they are free to draft a SAR on SOLs. This was not an SOL SAR.

TOP-002-2:
MISO Stakeholders proposes that the Standards DT (not the SAR DT) decide on whether or not to keep R8. The SAR DT thanks MISO Stakeholders for their agreement to keep this requirement within scope.

Regarding **R14** and **R15** MISO Stakeholders has a position that they want to effect. That is a legitimate position, but the SAR DT cannot ensure that the MISO Stakeholders position will be agreed to in the standards process. MISO Stakeholders has the misconception that the Standards DT will write the final requirements. The Standards DT will not remove any requirements unless the industry approves of removing those requirements.

Regarding monitoring requirements, MISO Stakeholders has a position on the requirements and they ask that the SAR DT protect that position. It is not the responsibility of the DT to protect a given company's position. This SAR is a scoping

Question #1			
Commenter	**Yes**	**No**	**Comment**
document not a process to ensure any one position. The idea of protecting equipment from damage is a laudable goal but it is not a goal of this SAR. To be a goal of a standard, the term Equipment damage would need to be defined. This DT does not include that concern in its purpose. Regarding Generation adequacy, that is outside the purpose of this SAR. Adequacy will be dealt with in a separate SAR. Here again, there is no reason MISO Stakeholders can not submit its own SAR to address this concern.			
American Transmission Co.		☑	The SDT has not provided any information as to scope of work that will be performed on IRO-004, 005 and 006 in the posted version of the SAR. Therefore ATC does not agree with the expanded scope. The SAR SDT must provide information as to why these standards must be worked on as part of this effort. We request that the SAR SDT provided the necessary information and post a revised version of the SAR for comment. Additional comments: Issue 1: A majority of comments submitted on Question 2 (Initial SAR posting) did not support the SDT proposal to remove SOL requirements from NERC's Reliability Standards. ATC believes that SOLs are a BES issue and must continue to be part of NERC Reliability Standards. ATC does not agree with the SDT proposed compromise that would limit Reliability Standards to only requiring monitoring of SOL. (Note: The SAR provides little to no justification as to why SOL should be removed from NERC Reliability Standards.) "Question 2 (initial SAR posting): The SAR DT believes that SOLs, while very important to local utility operations, are not a true Bulk Electric System reliability issue, and as such, believes that any requirements related to SOLs should be moved into guides or other reference documents, to be added to the literature on 'good utility practice'. Do you agree?" Issue 2: ATC continues to disagree with the current scope of work. We find that scope of work's description is overly prescriptive and not complete. It seems that the SAR is attempting to remove requirements that address SOL conditions from NERC standards but that is never specifically stated in the SAR. It's also import to note that in Appendix B of the SAR no specific request was made to remove SOL from NERC standards. Many of the requests in Appendix B only support clarification and removal of redundant

Question #1			
Commenter	**Yes**	**No**	**Comment**
			requirements. It's our position that the effort to remove SOLs from NERC standards will reduce interconnection reliability. Therefore ATC can not support this SAR until a proper scope of work is developed. The scope should be limited to clarifying existing requirements by; removing redundancy, better alignments of requirements to measures and removal/clarification of ambiguous language. Issue 2a: COM-001 Is currently being worked on in projects 2006-04 & 2006-06 COM-002 Is currently being worked on in projects 2006-06 & 2007-02 IRO-004 Is currently being worked on in project 2007-02 IRO-005 Is currently being worked on in project 2007-02 & 2007-18 IRO-006 Is currently being worked on in project 2006-08 Lastly ATC believes that this project should be delayed until the all previously identified efforts have been completed in order to insure an efficient work flow. If this project is moved into the standard development phase five Standards will have parallel efforts on going. Coordination will be extremely difficult if not impossible to manage.

ATC does not support expanding the scope.

Response:

ATC requests a response to why the SAR DT asked to include the subject three standards. Answer: In reviewing a comment received during the last round of comments, it was brought to the DT's attention that there were redundancies in IRO004, 005 and 006. In order to address those redundancies it was necessary to ask the industry if the scope could be expanded. As these three standards have been found acceptable to the majority of the current commenters, the SAR DT will now include them in the scope and will post the new SAR for approval.

Issue 1. The purpose of the SAR is to remove redundancies, the issue of SOLs is left to the Industry decide by the process. If this particular SAR does not meet ATC's concerns then ATC should submit its own request.

Question #1			
Commenter	**Yes**	**No**	**Comment**
Regarding the question of being prescriptive (which in the next paragraph ATC states we should further limit) - the SAR DT was prescriptive in exactly what is to be in the scope of work. The idea was to ensure that the Standards DT isn't inundated with other people's unrelated issues. ATC states that the scope is incomplete but does not specify how to complete it. Is it a redundancy that was missed or is it an unrelated issue? The SAR simply proposes a scope of work designed primarily to eliminate redundancies. Deletion or changes to existing requirements would occur in the standards drafting process. We agree with ATC that the scope should be focused (i.e., prescriptive) on removing redundancies. For items that are not included in this SAR's scope, ATC is encouraged to submit its own scope of work Regarding **Issue 2a** – ATC lists a number of standards that are addressed in various other NERC projects. The SAR DT would remind ATC that each standard has more than one requirement. And it is these diverse requirements that each Project is addressing. If there is overlapping requirements then ATC is encouraged to bring that to the attention of NERC Staff. **Lastly**, the SAR DT works at the will of NERC. The DT was assigned to begin its work and complete its scoping document. If ATC does not agree with NERC starting this project, then they should inform the NERC staff and the NERC Standards Committee of their concerns.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
Hydro-Québec TransÉnergie		☑	Both IRO-006-3 and draft IRO-006-4 have the TOP listed in applicability section. However, neither actually has any requirement in the standard. They simply reference the TOP in the requirements. We think that the scope should not be restricted to only eliminate redundancy in IRO-004, -005 and -006 but should permit other changes in those standards. Hydro-Québec TransÉnergie would probably have some proposition to make because of the characteristics of Québec Interconnexion. The SAR drafting team should modify the scope so that all requirements to monitor and control flows within SOLs are not eliminated. While the SAR drafting team points out in their response to the comments that NERC's definition defines an SOL as local, eliminating all requirements to monitor and control to SOLs will be detrimental to reliability. Multiple SOLs occuring on a system may be a sign of an undetected IROL or, if left unchecked, propagate into an IROL. This was the cause of the August 14th blackout. Clearly there should be an obligation on the part of the TOP and RC to monitor and mitigate these limits to prevent such propagation.

HQ TransEnergie does not support expanding the scope.

Response:
The commenter is correct that the TOP is not in IRO-006.

When the Standards process begins, Hydro Quebec can suggest changes to those standards in scope. And if that is not suffcient Hydro Quebec is encougaged to submit its own SAR.

Regarding monitoring requirements, Hydro Quebec has a position on the requirements and they ask that the SAR DT protect that position. It is not the responsibility of the DT to protect a given position. This SAR is simply a scoping document.

IRO-005-2 R1 requires the RC to monitor SOLs. Clearly multiple SOLs in different parts of a system can only be coordinated by an RC. At best a TOP can only deal with its own limited subset. That is a current requirement and unless changed through the Reliability Standards Development Procedure, that requirement will remain.

Maureen E. Long
Standards Process Manager

November 13, 2007

TO: REGISTERED BALLOT BODY

Ladies and Gentlemen:

Announcement: Nomination Period Opens for Standard Drafting Team

The Standards Committee announces the following standards action:

Nominations for Project 2007-03 Real-time Operations Standards Drafting Team (November 13–November 30, 2007)

The Standards Committee is seeking industry experts to serve on the Real-time Operations Standards Drafting Team. The drafting team will work to modify the following standards:

- COM-001 — Telecommunications
- COM-002 — Communications and Coordination
- IRO-004 — Reliability Coordination — Operations Planning
- IRO-005 — Reliability Coordination — Current Day Operations
- IRO-006 — Reliability Coordination — Transmission Loading Relief
- TOP-001 — Reliability Responsibilities and Authorities
- TOP-002 — Normal Operations Planning
- TOP-003 — Planned Outage Coordination
- TOP-004 — Transmission Operations
- TOP-005 — Operational Reliability Information
- TOP-006 — Monitoring System Conditions
- TOP-007 — Reporting SOL and IROL Violations
- TOP-008 — Response to Transmission Violations
- PER-001 — Operating Personnel Responsibility and Authority

If you are interested in serving on this standard drafting team, please complete this nomination form and send it to sarcomm@nerc.net by November 30, 2007 with the words "Real-time SDT" in the subject line. For questions, please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net.

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. If you have any questions, please contact me at 813-468-5998 or maureen.long@nerc.net.

Sincerely,

Maureen E. Long

cc: Registered Ballot Body Registered Users
Standards Mailing List
NERC Roster

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Nomination Form for Real-time Operations Standard Drafting Team (Project 2007-03)

Please return this form to sarcomm@nerc.net by November 30, 2007 with the words "Real-time SDT" in the subject line. If you have any questions, please contact Ed Dobrowolski at 609-947-3673 or ed.dobrowolski@nerc.net.

All candidates should be prepared to participate actively at these meetings.

Name: Organization: Address: Office Telephone: E-mail:
Please briefly describe your experience and qualifications to serve on the Real-time Operations Standards Drafting Team. Prefer experience in managing real-time operations for entities registered as Transmission Operators, Transmission Owners, Balancing Authorities and Reliability Coordinators. Previous experience working on or applying NERC or IEEE standards is beneficial, but not a requirement.

I represent the following NERC Reliability Region(s) (check all that apply):	**I represent the following Industry Segment (check one):**	
☐ ERCOT ☐ FRCC ☐ MRO ☐ NPCC ☐ RFC ☐ SERC ☐ SPP ☐ WECC ☐ NA – Not Applicable	☐	1 — Transmission Owners
	☐	2 — RTOs, ISOs
	☐	3 — Load-serving Entities
	☐	4 — Transmission-dependent Utilities
	☐	5 — Electric Generators
	☐	6 — Electricity Brokers, Aggregators, and Marketers
	☐	7 — Large Electricity End Users
	☐	8 — Small Electricity End Users
	☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
	☐	10 — Regional Reliability Organizations and Regional Entities

Which of the following Function(s)[1] do you have expertise or responsibilities:

☐ Balancing Authority	☐ Planning Coordinator
☐ Compliance Enforcement Authority	☐ Transmission Operator
☐ Distribution Provider	☐ Transmission Owner
☐ Generator Operator	☐ Transmission Planner
☐ Generator Owner	☐ Transmission Service Provider
☐ Interchange Authority	☐ Purchasing-selling Entity
☐ Load-serving Entity	☐ Resource Planner
☐ Market Operator	☐ Reliability Coordinator

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group.

Name:	Office Telephone:
Organization:	E-mail:
Name:	Office Telephone:
Organization:	E-mail:

[1] These functions are defined in the NERC Functional Model, which is downloadable from the NERC Web site.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The schedule shows completion of the project in 3Q09. The current draft is the first posting of the revised standards. As part of the proposed revisions, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project Pre-2006, Operate Within Interconnection Reliability Operating Limits (IRO-008 through IRO-010), and Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. First posting of revised standards.	October 2008
2. Second posting of revised standards.	January 2009
3. Third posting of revised standards.	April 2009
4. Post for ballot.	July 2009
5. Post for re-ballot.	September 2009
6. Submit to BOT.	September 2009
7. Submit to regulatory authorities for approval.	October 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. Title: **Coordination of Transmission Operations**

2. Number: TOP-001-2

3. Purpose:

To ensure coordination between and among functional entities for the reliability of the Bulk Electric System (BES).

4. Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

4.4. Distribution Providers

4.5. Load-Serving Entities

5. Effective Date: All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless the respective entity informs the Transmission Operator that such actions would violate safety, equipment, regulatory or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of Real-Time or anticipated Emergency conditions, including potential impacts caused by disconnections prior to switching. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall render emergency assistance to others, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R4. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to affect other reliability entities with those entities unless System conditions do not permit such coordination. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R6. The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R7. Each Transmission Operator shall operate the Bulk Electric System to the most limiting parameter when there is a difference in derived operating limits amongst reliability entities. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall each make available upon request, in accordance with Requirement R1, evidence that it either: (a) complied with reliability directives issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. The Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and affected Transmission Operators of Real-Time or anticipated Emergency conditions, including potential impacts caused by disconnections prior to switching, in accordance with Requirement R2. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M3. The Transmission Operator, Balancing Authority, and Generator Operator shall each make available upon request, evidence that requested and available emergency assistance was rendered to others in accordance with Requirement R3 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. The Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among affected reliability entities in accordance with Requirement R4 unless System conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M5. The Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M6. The Transmission Operator shall make available evidence of when it acted or directed others to mitigate the magnitude and duration of exceeding an IROL within the IROL's

Tv in accordance with Requirement R6. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M7. The Transmission Operator shall make available evidence such as dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts, of any occasion when it operated to a limiting parameter due to differing operating limits amongst reliability entities in accordance with Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall each retain for the current calendar year and one previous calendar year, in accordance with Requirement R1 and Measurement M1, evidence that it either: (a) complied with reliability directives issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements.
- The Transmission Operator shall retain evidence for the current calendar year and one previous calendar year that it has informed its Reliability Coordinator and affected Transmission Operators of Real-Time or anticipated Emergency conditions in accordance with Requirement R2 and Measurement M2.

- The Transmission Operator, Balancing Authority, and Generator Operator shall retain evidence for the current calendar year and one previous calendar year that requested and available emergency assistance was rendered to others in accordance with Requirement R3 and Measurement M3 unless such actions would violate safety, equipment, regulatory, or statutory requirements.
- The Transmission Operator and Generator Operator shall retain evidence for the current calendar year and one previous calendar year that operations known or expected to affect other Reliability Entities were coordinated among affected Reliability Entities in accordance with Requirement R4 and Measurement M4 unless System conditions do not permit such coordination.
- The Transmission Operator shall make available evidence for three calendar years that it has informed its Reliability Coordinator of actions being taken to return the System to within limits when an IROL or SOL has been exceeded in accordance with Requirement R5 and Measurement M5.
- The Transmission Operator shall make available evidence of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv in accordance with Requirement R6 and Measurement M6.
- The Transmission Operator shall retain evidence for the current calendar year and one previous calendar year of any occasion when it operated to a limiting parameter due to differing operating limits amongst reliability entities in accordance with Requirement R7 and Measurement M7.

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements on one occasion.	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements on two occasions.	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements on three occasions.	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements on four or more occasions.
R2	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of real- time or Emergency conditions on one occasion.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of real- time or Emergency conditions on two occasions.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of real- time or Emergency conditions on three occasions.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of real- time or Emergency conditions on four or more occasions.
R3	N/A	N/A	N/A	The Transmission Operator, Balancing Authority, or Generator Operator did not render emergency assistance to others, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

	Lower	Moderate	High	Severe
R4	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to affect other reliability entities with one affected reliability entity or 25% or less of the affected reliability entities unless System conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to affect other reliability entities with two affected reliability entities or more than 25% or less than or equal to 50% of the affected reliability entities unless System conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to affect other reliability entities with three affected reliability entities or more than 50% or less than or equal to 75% of the affected reliability entities unless System conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to affect other reliability entities with four or more affected entities or more than 75% of the affected entities unless System conditions did not permit such coordination.
R5	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on one occasion.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on two occasions.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on three occasions.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on four or more occasions.
R6	The Transmission Operator did not make available evidence of the timing of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on one occasion.	The Transmission Operator did not make available evidence of the timing of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on two occasions.	The Transmission Operator did not make available evidence of the timing of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on three occasions.	The Transmission Operator did not make available evidence of the timing of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on four or more occasions.

	Lower	Moderate	High	Severe
R7	The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on one occasion.	The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on two occasions.	The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on three occasions.	The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on four or more occasions.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.

Proposed Action Plan and Description of Current Draft:

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. First posting of revised standards.	October 2008
2. Second posting of revised standards.	January 2009
3. Third posting of revised standards.	April 2009
4. Post for ballot.	July 2009
5. Post for re-ballot.	September 2009
6. Submit to BOT.	September 2009
7. Submit to regulatory authorities for approval.	October 2009

Definitions of Terms Used in Standard

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Simulated Contingencies – The act of using planning and operating models to replicate Contingency responses that depict the net effect of design considerations

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that reliability entities have coordinated plans for meeting expected operating conditions.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and Simulated Contingency events. *[Violation Risk Factor: Low] [Time Horizon: Same-day Operations]*

R2. The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R3. The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

C. Measures

M1. The Transmission Operator shall have evidence that it has assessed next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated operator logs or reports.

M2. The Transmission Operator shall have evidence that it has planned to preclude operating in excess of the IROLs identified as a result of the assessment performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL.

M3. The Transmission Operator shall make available evidence that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

   1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall retain evidence for a rolling six month period that it has assessed next day operations in accordance with Requirement R1 and Measurement M1.
- The Transmission Operator shall retain evidence for a rolling six month period that it has planned to preclude operating in excess of any IROL identified as a result of the assessment performed in Requirement R1 in accordance with Requirement R2 and Measurement M2.
- The Transmission Operator shall retain evidence for a rolling twelve-month period that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3 and Measurement M3.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not perform an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of any IROLs identified as a result of the assessment performed in Requirement R1.
R3	The Transmission Operator did not notify one of the reliability entities or 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two of the reliability entities or more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three of the reliability entities or more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more of the reliability entities or more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
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The SDT began meeting in January 2008 following the approval of the SAR by the SC. The schedule shows completion of the project in 3Q09. The current draft is the first posting of the revised standards. As part of the proposed revisions, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project Pre-2006, Operate Within Interconnection Reliability Operating Limits (IRO-008 through IRO-010), and Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. First posting of revised standards.	October 2008
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Definitions of Terms Used in Standard

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**
2. **Number:** TOP-003-1
3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to plan and operate the Transmission system.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Generator Owners.
   - **4.4.** Generator Operators.
   - **4.5.** Interchange Authorities.
   - **4.6.** Load-Serving Entities.
   - **4.7.** Transmission Owners.
5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data to support its Real-time monitoring and reliability assessments. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

- **R1.1.** A list of required data to be exchanged.
- **R1.2.** A mutually agreeable format.
- **R1.3.** A timeframe and periodicity for providing data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data to support its reliability assessments in accordance with Requirement R1.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall make available evidence that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) in accordance with Requirement R4. The data is limited to that needed by the Transmission Operator to support Operational Planning Analyses and reliability assessments. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for data to support their reliability assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall retain evidence for 90 calendar days that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) in accordance with Requirement R4 and Measurement M4.
- Each Transmission Operator and Balancing Authority shall retain evidence for 90 calendar days that it has provided to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those entities necessary for reliability assessments and Real-Time operations in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator or Balancing Authority did not have one of the required elements of the documented specification for data to support its real-time monitoring and reliability assessments.	The Transmission Operator or Balancing Authority did not have two of the required elements of the documented specification for data to support its real-time monitoring and reliability assessments.	N/A	The Transmission Operator or Balancing Authority did not have a documented specification for data and information to support its real-time monitoring and reliability assessments.
R2	The Transmission Operator did not distribute its data specification to one entity or 25% or less of the entities that has Facilities monitored by the Transmission Operator or to one entity or 25% or less of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to two entities or more than 25% and less than or equal to50% of the entities that have Facilities monitored by the Transmission Operator or to two entities or more than 25% and less than or equal to 50% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to three entities or more than 50% and less than or equal to 75% of the entities that have Facilities monitored by the Transmission Operator or to three entities or more than 50% and less than or equal to 75% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to four or more entities or more than 75% of the entities that have Facilities monitored by the Transmission Operator or to four or more entities or more than 75% of the entities that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to one entity or 25% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to two entities or more than 25% and less than or equal to 50% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to three entities or more than 50% and less than or equal to 75% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to four or more entities or more than 75% of the entities that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, or Transmission Owner did not

				provide data and information, as specified in Requirement R1, to its Transmission Operator(s).
R5	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not provide to other Transmission Operators or Balancing Authorities with immediate responsibility for operational reliability, the data and information requested by those entities necessary for real-time monitoring and reliability assessments.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

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1. First posting of revised standards.	October 2008
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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Real-time Transmission Operations**

2. **Number:** TOP-004-3

3. **Purpose:** To ensure that Transmission Operators act to preserve the reliability of the Bulk Electric System in Real-time.

4. **Applicability:**

   4.1. Transmission Operators.

5. **Proposed Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limits (IROLs) and its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R2. Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside identified Interconnection Reliability Operating Limits (IROLs) and their associated IROL T_v as specified in Requirement R1. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion outside of the identified IROL and applicable IROL T_v.

M2. Each Transmission Operator shall make available evidence that it has Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2. Such evidence could include but is not limited to a dated document with confirmation of the Agreement in electronic or hard copy format.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity

   1.2. Compliance Monitoring and Reset Time Frame

   Not applicable

   1.3. Compliance Monitoring and Enforcement Processes

   Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Exception Reporting of any occasion in which it has operated outside an identified IROL and the applicable IROL T_v as specified in Requirement R1 and Measurement M1.

1.4. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside identified IROL and its associated IROL T_v as specified in Requirement R1 and Measurement M1.
- The Transmission Operator shall retain evidence that it has current in force Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2 and Measurement M2 as well as any Agreements in force since the last compliance audit.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

Submit exception reports of each instance of exceeding an IROL for time greater than the associated IROL T_v to the Compliance Enforcement Authority within thirty calendar days of the event.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not operate within an identified Interconnection Reliability Operating Limits (IROL) and the associated IROL T_v for any single occasion.
R2	The Transmission Operator does not have Agreements with one of its directly interconnected Transmission Operators or 25% or less of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	The Transmission Operator does not have Agreements with two of its directly interconnected Transmission Operators or more than 25% and less than or equal to 50% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	The Transmission Operator does not have Agreements with three of its directly interconnected Transmission Operators or more than 50% and less than or equal to 75% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	The Transmission Operator does not have Agreements with four or more of its directly interconnected Transmission Operators or more than 75% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata
3	TBD	Changes pursuant to Project 2007-03	Revised

Deleted: 1

Deleted: Reliability Responsibilities and Authorities

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5. SAR approved by SC on November 1, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The schedule shows completion of the project in 3Q09. The current draft is the first posting of the revised standards. As part of the proposed revisions, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project Pre-2006, Operate Within Interconnection Reliability Operating Limits (IRO-008 through IRO-010), and Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. First posting of revised standards.	October 2008
2. Second posting of revised standards.	January 2009
3. Third posting of revised standards.	April 2009
4. Post for ballot.	July 2009
5. Post for re-ballot.	September 2009
6. Submit to BOT.	September 2009
7. Submit to regulatory authorities for approval.	October 2009

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Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

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A. Introduction

1. **Title:** **Coordination of Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:**

To ensure coordination between and among functional entities for the reliability of the Bulk Electric System (BES).

4. **Applicability**

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

4.4. Distribution Providers

4.5. Load-Serving Entities

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless the respective entity informs the Transmission Operator that such actions would violate safety, equipment, regulatory or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of Real-Time or anticipated Emergency conditions, including potential impacts caused by disconnections prior to switching. *[Violation Risk Factor:High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall render emergency assistance to others, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R4. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to affect other reliability entities with those entities unless System conditions do not permit such coordination. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R4.1.

R5. Each Transmission Operator shall inform its Reliability Coordinator ~~when an IROL or SOL has been exceeded and the~~ of actions being taken to return the system to within limits when an

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Deleted: reliability … have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency … [2]

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Comment [Edd1]: This statement is not needed in a reliability standard. The standards already require the necessary actions. This statement doesn't really protect the operator.

Comment [Edd2]: Deleted for similar reasoning to R1.

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IROL or SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R6. The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_V. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R7. Each Transmission Operator shall operate the Bulk Electric System to the most limiting parameter when there is a difference in derived operating limits amongst reliability entities. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall each make available upon request, in accordance with Requirement R1, evidence that it either: (a) complied with reliability directives issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. The Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and affected Transmission Operators of Real-Time or anticipated Emergency conditions, including potential impacts caused by disconnections prior to switching, in accordance with Requirement R2. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M3. The Transmission Operator, Balancing Authority, and Generator Operator shall each make available upon request, evidence that requested and available emergency assistance was rendered to others in accordance with Requirement R3 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. The Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among affected reliability entities in accordance with Requirement R4 unless System conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M5. The Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M6. The Transmission Operator shall make available evidence of when it acted or directed others to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_V in accordance with Requirement R6. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M7. The Transmission Operator shall make available evidence such as dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts, of any occasion

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Comment [Edd9]: This requirement was moved here from TOP-007-0, R2.

Comment [Edd10]: Moved from TOP-008, R2. .

Deleted: <#>Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.

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Deleted: <#>If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)

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when it operated to a limiting parameter due to differing operating limits amongst reliability entities in accordance with Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall each retain for the current calendar year and one previous calendar year, in accordance with Requirement R1 and Measurement M1, evidence that it either: (a) complied with reliability directives issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements.
- The Transmission Operator shall retain evidence for the current calendar year and one previous calendar year that it has informed its Reliability Coordinator and affected Transmission Operators of Real-Time or anticipated Emergency conditions in accordance with Requirement R2 and Measurement M2.
- The Transmission Operator, Balancing Authority, and Generator Operator shall retain evidence for the current calendar year and one previous calendar year that requested and available emergency assistance was rendered to others in accordance with Requirement R3 and Measurement M3 unless such actions would violate safety, equipment, regulatory, or statutory requirements.

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Deleted: that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

Deleted: Monitoring Responsibility

Deleted: Reliability Organizations shall be responsible for compliance monitoring.

Deleted: One or more of the following methods will be used to assess compliance:¶
<#>Self-certification (Conducted annually with submission according to schedule.)¶
<#>Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.) ¶
<#>Periodic Audit (Conducted once every three years according to schedule.)¶
<#>Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)¶
The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

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Deleted: Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)¶
Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.¶
Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.¶
Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures ... [23]

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- The Transmission Operator and Generator Operator shall retain evidence for the current calendar year and one previous calendar year that operations known or expected to affect other Reliability Entities were coordinated among affected Reliability Entities in accordance with Requirement R4 and Measurement M4 unless System conditions do not permit such coordination.
- The Transmission Operator shall make available evidence for three calendar years that it has informed its Reliability Coordinator of actions being taken to return the System to within limits when an IROL or SOL has been exceeded in accordance with Requirement R5 and Measurement M5.
- The Transmission Operator shall make available evidence of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v in accordance with Requirement R6 and Measurement M6.
- The Transmission Operator shall retain evidence for the current calendar year and one previous calendar year of any occasion when it operated to a limiting parameter due to differing operating limits amongst reliability entities in accordance with Requirement R7 and Measurement M7.

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Deleted: Levels of Non-Compliance for a Balancing Authority:

	Lower	Moderate	High	Severe
R1	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such

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	actions would violate safety, equipment, regulatory, or statutory requirements on one occasion.	actions would violate safety, equipment, regulatory, or statutory requirements on two occasions.	actions would violate safety, equipment, regulatory, or statutory requirements on three occasions.	actions would violate safety, equipment, regulatory, or statutory requirements on four or more occasions.
R2	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of real-time or Emergency conditions on one occasion.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of real-time or Emergency conditions on two occasions.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of real-time or Emergency conditions on three occasions.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of real-time or Emergency conditions on four or more occasions.
R3	N/A	N/A	N/A	The Transmission Operator, Balancing Authority, or Generator Operator did not render emergency assistance to others, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements.
R4	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to affect other reliability entities with one affected reliability entity or 25% or less of the	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to affect other reliability entities with two affected reliability entities or more than 25% or less than or	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to affect other reliability entities with three affected reliability entities or more than 50% or less than or	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to affect other reliability entities with four or more affected entities or more than 75% of the affected

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	affected reliability entities unless System conditions did not permit such coordination.	equal to 50% of the affected reliability entities unless System conditions did not permit such coordination.	equal to 75% of the affected reliability entities unless System conditions did not permit such coordination.	entities unless System conditions did not permit such coordination.
R5	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on one occasion.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on two occasions.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on three occasions.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on four or more occasions.
R6	The Transmission Operator did not make available evidence of the timing of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on one occasion.	The Transmission Operator did not make available evidence of the timing of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on two occasions.	The Transmission Operator did not make available evidence of the timing of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on three occasions.	The Transmission Operator did not make available evidence of the timing of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on four or more occasions.
R7	The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on one occasion.	The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on two occasions.	The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on three occasions.	The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on four or more occasions.

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E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

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Level 2: Not applicable.¶
Level 3: Not applicable.¶
Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation: ¶
Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)¶
Did not render emergency assistance to others as requested, in accordance with R6.¶
Levels of Non-Compliance for a Transmission Operator¶
Level 1: Not applicable.¶
Level 2: Not applicable. ¶
Level 3: Not applicable.¶
Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation: ¶
Does not have the documented authority to act as specified in R1.¶
Does not have evidence it acted with the authority specified in R1. ¶
Did not take immediate actions to alleviate operating emergencies as specified in R2.¶
Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.¶
Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.¶
Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.¶
Did not render emergency assistance to others as requested, as specified in R6.¶
Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.¶
Levels of Non-Compliance for a Generator Operator:¶
Level 1: Not applicable.¶ ... [24]

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Reliability Responsibilities and Authorities

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reliability

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have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency

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Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies

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Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc

Page 3: [5] Comment [Edd3]	Edd	9/25/2008 11:05:00 AM

All references to the RC and RC responsibility have been removed as they are now covered as part of Project 2006-06.

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by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued

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Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

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Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load

Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

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any other potentially

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and take actions to avoid, when possible, or mitigate the emergency

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Deleted phrase due to redundancy with TOP-004-2, R1.

Page 3: [10] Comment [Edd5]	**Edd**	**9/25/2008 11:05:00 AM**

Moved phrase from TOP-008, R3.

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all available

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provided that the requesting entity has implemented its comparable emergency procedures,

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or

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not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:

Page 3: [13] Comment [Edd6]	**Edd**	**9/25/2008 11:05:00 AM**

The sub-requirements have been incorporated into the main requirement.

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For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the

Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

Page 3: [15] Comment [Edd7] **Edd** **9/25/2008 11:05:00 AM**

Deleted due to redundancy with CPS, DCS, and VAR standards. Deleted requirement for real power as redundant with EOP-002-2, R1 & R6. This is only applicable to the BA. Deleted requirement for reactive as one can't supply emergency reactive assistance remotely.

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During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding

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Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)

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Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)

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The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

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The Transmission Operator, Balancing Authority, and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)

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Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

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Level 1: Not applicable.

Level 2: Not applicable.

Level 3: Not applicable.

Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

Did not render emergency assistance to others as requested, in accordance with R6.

Levels of Non-Compliance for a Transmission Operator

Level 1: Not applicable.

Level 2: Not applicable.

Level 3: Not applicable.

Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

Does not have the documented authority to act as specified in R1.

Does not have evidence it acted with the authority specified in R1.

Did not take immediate actions to alleviate operating emergencies as specified in R2.

Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.

Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.

Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.

Did not render emergency assistance to others as requested, as specified in R6.

Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

Levels of Non-Compliance for a Generator Operator:

Level 1: Not applicable.

Level 2: Not applicable.

Level 3: Not applicable.

Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.

Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.

Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

Levels of Non-Compliance for a Distribution Provider or Load Serving Entity

Level 1: Not applicable.

Level 2: Not applicable.

Level 3: Not applicable

Level 4: Did not comply with a Transmission Operator's reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
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Proposed Action Plan and Description of Current Draft:

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. First posting of revised standards.	October 2008
2. Second posting of revised standards.	January 2009
3. Third posting of revised standards.	April 2009
4. Post for ballot.	July 2009
5. Post for re-ballot.	September 2009
6. Submit to BOT.	September 2009
7. Submit to regulatory authorities for approval.	October 2009

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Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Simulated Contingencies – The act of using planning and operating models to replicate Contingency responses that depict the net effect of design considerations

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A. Introduction

1. **Title:** **Operations Planning**
2. **Number:** TOP-002-3
3. **Purpose:** To ensure that reliability entities have coordinated plans for meeting expected operating conditions.
4. **Applicability**

   4.1.

   4.2. Transmission Operator.

   4.3.

   4.4.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and Simulated Contingency events. *[Violation Risk Factor: Low] [Time Horizon: Same-day Operations]*

R2. The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

R3. The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). *[Violation Risk Factor: High] [Time Horizon: Same-day Operations]*

C. Measures

M1. The Transmission Operator shall have evidence that it has assessed next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated operator logs or reports.

M2. The Transmission Operator shall have evidence that it has planned to preclude operating in excess of the IROLs identified as a result of the assessment performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL.

M3. The Transmission Operator shall make available evidence that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall retain evidence for a rolling six month period that it has assessed next day operations in accordance with Requirement R1 and Measurement M1.
- The Transmission Operator shall retain evidence for a rolling six month period that it has planned to preclude operating in excess of any IROL identified as a result of the assessment performed in Requirement R1 in accordance with Requirement R2 and Measurement M2.
- The Transmission Operator shall retain evidence for a rolling twelve-month period that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3 and Measurement M3.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

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Deleted: Monitoring Responsibility

Deleted: Reliability Organizations shall be responsible for compliance monitoring.

Deleted: One or more of the following methods will be used to assess compliance:¶
<#>Self-certification (Conducted annually with submission according to schedule.)¶
<#>Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.) ¶
<#>Periodic Audit (Conducted once every three years according to schedule.)¶
<#>Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)¶
The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

Deleted: For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).¶
For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).¶
For Measure 4, each Transmission Operator shall keep its current plans (evidence).¶
For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).¶
For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).¶
For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.¶
If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.¶
Evidence used as part of a trigge ... [29]

Deleted: of Non-Compliance for Balancing Authorities:

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	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not perform an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of any IROLs identified as a result of the assessment performed in Requirement R1.
R3	The Transmission Operator did not notify one of the reliability entities or 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two of the reliability entities or more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three of the reliability entities or more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more of the reliability entities or more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata

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Level 2: Not applicable.
Level 3: Not applicable.
Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
Did not maintain an updated set of current-day plans as specified in R1.
Plans did not meet one or more of the requirements specified in R5 through R10.
Levels of Non-Compliance for Transmission Operators
Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.
Level 2: Not applicable.
Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.
Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:
Did not maintain an updated set of current-day plans as specified in R1.
Plans did not meet one or more of the requirements in R5, R6, and R10.
Studies not updated to reflect current system conditions as specified in R11.
Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.
Levels of Non-Compliance for Generator Operators:
Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.
Level 2: Not applicable.
Level 3: Not applicable.
Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in ... [30]

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1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Changes pursuant to Project 2007-03	Revised

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Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events

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Transmission Service Provider.

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Six months after effective date of VAR-001-1.

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Deleted as BA only needs to respond to CPS and DCS and thus was not applicable. TOP now covered in new R21 below.

Page 3: [7] Comment [Edd2]	Edd	9/25/2008 2:29:00 PM

Deleted as good utility practice and unmeasurable.

Page 3: [8] Comment [Edd3]	Edd	9/25/2008 2:29:00 PM

LSE and GOP are governed by their Interconnection Operating Agreement and therefore not necessary here. TSP deleted as not applicable. TOP covered in new R22.

Page 3: [9] Comment [Edd4]	Edd	9/25/2008 2:30:00 PM

Deleted as duplicative of proposed IRO-001-2, R1.

Page 3: [10] Comment [Edd5]	Edd	9/25/2008 2:30:00 PM

Replaced with R20.

Page 3: [11] Comment [Edd6]	Edd	9/25/2008 2:31:00 PM

BA deleted as covered in BAL-002-0, R4. TOP covered in new R21.

Page 3: [12] Comment [Edd7]	Edd	9/25/2008 2:31:00 PM

Deleted as duplicative of BAL-002-0, R1.

Page 3: [13] Comment [Edd8]	Edd	9/25/2008 2:32:00 PM

Delete as not applicable to BA.

Page 3: [14] Comment [Edd9] **Edd** **9/25/2008 2:32:00 PM**

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Page 3: [15] Comment [Edd10] **Edd** **9/25/2008 2:32:00 PM**

Delete as not applcable to BA. TOP covered in new R21.

Page 3: [16] Comment [Edd11] **Edd** **9/25/2008 2:33:00 PM**

First sentence covered in new R20. Second sentence covered in proposed IRO-009-1 as well as FAC-010-1, FAC-011-1, and FAC-014-1. Third sentence covered in new R22.

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Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained

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Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose

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Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator

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Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner

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Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns

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ach Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements

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Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency

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Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency

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Each Balancing Authority shall plan to meet Interchange Schedules and ramps

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Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs

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The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator

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Adopted by Board of Trustees: November 1, 2006

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For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

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Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

Level 2: Not applicable.

Level 3: Not applicable.

Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

Did not maintain an updated set of current-day plans as specified in R1.

Plans did not meet one or more of the requirements specified in R5 through R10.

Levels of Non-Compliance for Transmission Operators

Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

Level 2: Not applicable.

Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.

Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

Did not maintain an updated set of current-day plans as specified in R1.

Plans did not meet one or more of the requirements in R5, R6, and R10.

Studies not updated to reflect current system conditions as specified in R11.

Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

Levels of Non-Compliance for Generator Operators:

Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

Level 2: Not applicable.

Level 3: Not applicable.

Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

Level 2: Not applicable.

Level 3: Not applicable.

Level 4: Not applicable.

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Standard Development Roadmap

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Definitions of Terms Used in Standard

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There are no new or revised definitions proposed in this standard revision.

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A. Introduction

1. **Title:** Operational Reliability Data
2. **Number:** TOP-003-1
3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to plan and operate the Transmission system.
4. **Applicability**
   - **4.1.**
   - **4.2.** Transmission Operators.
   - **4.3.** Balancing Authorities.
   - **4.4.**
   - **4.5.** Generator Owners.
   - **4.6.** Generator Operators.
   - **4.7.** Interchange Authorities.
   - **4.8.** Load-Serving Entities.
   - **4.9.** Transmission Owners.
5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data to support its Real-time monitoring and reliability assessments. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

- **R1.1.** A list of required data to be exchanged.
- **R1.2.** A mutually agreeable format.
- **R1.3.** A timeframe and periodicity for providing data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

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Deleted: Generator Operators.
Deleted: Reliability Coordinators.
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Comment [Edd1]: This requirement is now covered in the re-worded requirements below.
Comment [Edd2]: Deleted as now covered in IRO-001-2, R1 (proposed).
Comment [Edd3]: Deleted as now covered in.IRO-001-2, R1 (proposed)
Comment [Edd4]: Deleted as now covered in Project 2006-06.
Deleted: <#>Generator Operators and Transmission Operators shall provide planned outage information
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R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data to support its reliability assessments in accordance with Requirement R1.

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M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall make available evidence that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) in accordance with Requirement R4. The data is limited to that needed by the Transmission Operator to support Operational Planning Analyses and reliability assessments. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R9. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

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Deleted: Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.¶
Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

Compliance

1. Compliance Monitoring Process

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Deleted: A Reliability Coordinator makes a request for an outage to "not be taken" because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.1. Compliance Monitoring Process

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable

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1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

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Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

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- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for data to support their reliability assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall retain evidence for 90 calendar days that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) in accordance with Requirement R4 and Measurement M4.
- Each Transmission Operator and Balancing Authority shall retain evidence for 90 calendar days that it has provided to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those entities necessary for reliability assessments and Real-Time operations in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None

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2. Violation Severity Levels

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	Lower	Moderate	High	Severe
R1	The Transmission Operator or Balancing Authority did not have one of the required elements of the documented specification for data to support its real-time monitoring and reliability assessments.	The Transmission Operator or Balancing Authority did not have two of the required elements of the documented specification for data to support its real-time monitoring and reliability assessments.	N/A	The Transmission Operator or Balancing Authority did not have a documented specification for data and information to support its real-time monitoring and reliability assessments.
R2	The Transmission Operator did not distribute its data specification to one entity or 25% or less of the entities that has Facilities monitored by the Transmission Operator or to one entity or 25% or less of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to two entities or more than 25% and less than or equal to50% of the entities that have Facilities monitored by the Transmission Operator or to two entities or more than 25% and less than or equal to 50% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to three entities or more than 50% and less than or equal to 75% of the entities that have Facilities monitored by the Transmission Operator or to three entities or more than 50% and less than or equal to 75% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to four or more entities or more than 75% of the entities that have Facilities monitored by the Transmission Operator or to four or more entities or more than 75% of the entities that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to one entity or 25% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to two entities or more than 25% and less than or equal to 50% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to three entities or more than 50% and less than or equal to 75% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to four or more entities or more than 75% of the entities that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, or

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				Transmission Owner did not provide data and information, as specified in Requirement R1, to its Transmission Operator(s).
R5	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not provide to other Transmission Operators or Balancing Authorities with immediate responsibility for operational reliability, the data and information requested by those entities necessary for real-time monitoring and reliability assessments.

Deleted: **Level 1:** Each entity responsible for reporting information under Requirements R1 and R3 has a process in place to provide information to their Reliability Coordinator but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring Balancing Authority or Transmission Operator.¶
Level 2: N/A.¶
Level 3: N/A.¶
Level 4: There is no process in place to exchange outage information, or the entity responsible for reporting information under Requirements R1 to R3 does not follow the directives of the Reliability Coordinator to cancel or reschedule an outage.

E. Regional Variances

Deleted: Differences

None identified.

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Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

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Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.

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Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.

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Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

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Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required

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Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas

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Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts

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Style Definition: Requirement

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The schedule shows completion of the project in 3Q09. The current draft is the first posting of the revised standards. As part of the proposed revisions, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project Pre-2006, Operate Within Interconnection Reliability Operating Limits (IRO-008 through IRO-010), and Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. First posting of revised standards.	October 2008
2. Second posting of revised standards.	January 2009
3. Third posting of revised standards.	April 2009
4. Post for ballot.	July 2009
5. Post for re-ballot.	September 2009
6. Submit to BOT.	September 2009
7. Submit to governmental authorities.	October 2009

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Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

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A. Introduction

1. Title: **Real-time Transmission Operations**

2. Number: TOP-004-3

3. Purpose: To ensure that Transmission Operators act to preserve the reliability of the Bulk Electric System in Real-time.

4. Applicability:

4.1. Transmission Operators.

5. Proposed Effective Date: All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limits (IROLs) and its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R2. Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside identified Interconnection Reliability Operating Limits (IROLs) and their associated IROL T_v as specified in Requirement R1. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion outside of the identified IROL and applicable IROL T_v.

M2. Each Transmission Operator shall make available evidence that it has Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2. Such evidence could include but is not limited to a dated document with confirmation of the Agreement in electronic or hard copy format.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

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Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Exception Reporting of any occasion in which it has operated outside an identified IROL and the applicable IROL T_v as specified in Requirement R1 and Measurement M1.

1.4. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside identified IROL and its associated IROL T_v as specified in Requirement R1 and Measurement M1.
- The Transmission Operator shall retain evidence that it has current in force Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2 and Measurement M2 as well as any Agreements in force since the last compliance audit.

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If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

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Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.¶
If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.¶
Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor, ¶
The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.5. Additional Compliance Information

Submit exception reports of each instance of exceeding an IROL for time greater than the associated IROL T_v to the Compliance Enforcement Authority within thirty calendar days of the event.

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2. Violation Severity Levels

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R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not operate within an identified Interconnection Reliability Operating Limits (IROL) and the associated IROL T_v for any single occasion.
R2	The Transmission Operator does not	The Transmission Operator does not	The Transmission Operator does not	The Transmission Operator does not

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R#	Lower	Moderate	High	Severe
	have Agreements with one of its directly interconnected Transmission Operators or 25% or less of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	have Agreements with two of its directly interconnected Transmission Operators or more than 25% and less than or equal to 50% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	have Agreements with three of its directly interconnected Transmission Operators or more than 50% and less than or equal to 75% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	have Agreements with four or more of its directly interconnected Transmission Operators or more than 75% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.

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Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.¶
.**Level 3:** Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.¶
Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:¶
Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.¶
Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

E. Regional Variances

Deleted: Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata
3	TBD	Changes pursuant to Project 2007-03	Revised

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the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies

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Twelve months after BOT adoption of FAC-014.

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the

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and System Operating Limits (SOLs).

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This is now covered by R1 with the inclusion of IROL and IROL T_v.

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This is now covered by R1 with the inclusion of IROL and IROL T_v.

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Page 3: [7] Comment [Edd4] | **Edd** | **9/25/2008 4:02:00 PM**

The first sentence was deleted as unmeasurable. The second sentence was deleted as it is covered by TOP-001-1.

Page 3: [8] Comment [Edd5] | **Edd** | **9/25/2008 4:03:00 PM**

The first sentence was deleted as it is good utility practice. The second sentence was deleted as all of the sub-requirements were deleted:

R6.1 as duplicative of FAC-008 & FAC-009;

R6.2 as duplicative of VAR-001-1, R1 for voltage levels and reactive power and real power by R10;

R6.3 as it is now covered in new R3;

R6.4 as now covered in TOP-002-3;

R6.5 as already covered by FAC-011 & FAC-014; and

R6.6 as now covered in TOP-002-3.

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Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency

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Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator

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If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes

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Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area

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Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

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Monitoring and controlling voltage levels and real and reactive power flows.

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Switching transmission elements.

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Planned outages of transmission elements.

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Responding to IROL and SOL violations.

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Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.

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Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.

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Reliability Organizations shall be responsible for compliance monitoring.

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One or more of the following methods will be used to assess compliance:

Self-certification (Conducted annually with submission according to schedule.)

Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)

Periodic Audit (Conducted once every three years according to schedule.)

Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
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Proposed Action Plan and Description of Current Draft:

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. First posting of revised standards.	October 2008
2. Second posting of revised standards.	January 2009
3. Third posting of revised standards.	April 2009
4. Post for ballot.	July 2009
5. Post for re-ballot.	September 2009
6. Submit to BOT.	September 2009
7. Submit to regulatory authorities for approval.	October 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** ~~**Operational Reliability Information**~~

2. **Number:** ~~TOP-005-1~~

3. **Purpose:** ~~To ensure reliability entities have the operating data needed to monitor system conditions within their areas.~~

4. **Applicability**

   4.1. ~~Transmission Operators.~~

   4.2. ~~Balancing Authorities.~~

   4.3. ~~Reliability Coordinators.~~

   4.4. ~~Purchasing Selling Entities.~~

5. **Effective Date:** ~~November 1, 2006~~ All requirements will be retired on the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements are retired twenty-four months following Board of Trustees adoption.

B. Requirements

R1. ~~Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.~~

R1.1. ~~Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.~~

~~**R2.** As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."~~

R3. ~~Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.~~

R4. ~~Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.~~

C. Measures

M1. ~~Evidence that the Reliability Coordinator, Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.~~

D. Compliance

Comment [Edd1]: Deleted – covered by IRO-010-1, R3.

Comment [Edd2]: Deleted – covered in IRO-010.

Comment [Edd3]: Deleted – not a reliability concern.

Comment [Edd4]: Deleted – now covered in TOP-003-1.

Comment [Edd5]: Deleted – the PSE does not have any unique information needed by the TOP or BA.

Comment [Edd6]: Due to the large number of changes made to the requirements and measures, and the new format for compliance elements, the new compliance elements are only shown in the clean version for ease of reading and comprehension.

1. **Compliance Monitoring Process**

   1.1. **Compliance Monitoring Responsibility**

   ~~Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.~~

   ~~Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.~~

   1.2. **Compliance Monitoring Period and Reset Time Frame**

   ~~Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.~~

   1.3. **Data Retention**

   ~~Not specified.~~

   1.4. **Additional Compliance Information**

   Not specified.

2. **Levels of Non-Compliance**

   ~~**2.1. Level 1:** Each entity responsible for reporting information under Requirements R1 to R5 is providing the requesting entities with the data required, in specified time intervals and format, but there are problems with consistency of delivery identified in the measuring process that need remedy (e.g., the data is not supplied consistently due to equipment malfunctions, or scaling is incorrect).~~

   ~~**2.2. Level 2:** N/A.~~

   ~~**2.3. Level 3:** N/A.~~

   2.4. ~~**Level 4:** Each entity responsible for reporting information under Requirements R1 to R5 is not providing the requesting entities with data with the specified content, timeliness, or format. The information missing is included in the requesting entity's list of data.~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
2	TBD	TBD.	Pursuant to changes in Project 2007-03.

Attachment 1-TOP-005-0

Electric System Reliability Data

~~This Attachment lists the types of data that Reliability Coordinators, Balancing Authorities, and Transmission Operators are expected to provide, and are expected to share with each other~~.

3. ~~The following information shall be updated at least every ten minutes~~:

3.1. ~~Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint~~:

~~**3.1.1** Status.~~

~~**3.1.2** MW or ampere loadings.~~

~~**3.1.3** MVA capability.~~

~~**3.1.4** Transformer tap and phase angle settings.~~

3.1.5 ~~Key voltages~~.

~~**3.2.** Generator data.~~

~~**3.2.1** Status.~~

~~**3.2.2** MW and MVAR capability.~~

~~**3.2.3** MW and MVAR net output.~~

3.2.4 ~~Status of automatic voltage control facilities~~.

~~**3.3.** Operating reserve.~~

3.3.1 ~~MW reserve available within ten minutes~~.

~~**3.4.** Balancing Authority demand.~~

3.4.1 ~~Instantaneous~~.

~~**3.5.** Interchange.~~

~~**3.5.1** Instantaneous actual interchange with each Balancing Authority.~~

~~**3.5.2** Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.~~

3.5.3 ~~Interchange Schedules for the next 24 hours~~.

~~**3.6.** Area Control Error and frequency.~~

~~**3.6.1** Instantaneous area control error.~~

~~**3.6.2** Clock hour area control error.~~

3.6.3 ~~System frequency at one or more locations in the Balancing Authority~~.

~~**4.** Other operating information updated as soon as available.~~

~~**4.1.** Interconnection Reliability Operating Limits and System Operating Limits in effect.~~

~~**4.2.** Forecast of operating reserve at peak, and time of peak for current day and next day.~~

~~**4.3.** Forecast peak demand for current day and next day.~~

~~**4.4.** Forecast changes in equipment status.~~

~~**4.5.** New facilities in place.~~

~~**4.6.** New or degraded special protection systems.~~

~~**4.7.** Emergency operating procedures in effect.~~

~~**4.8.** Severe weather, fire, or earthquake.~~

4.9. ~~Multi-site sabotage~~.

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** ~~**Monitoring System Conditions**~~

2. **Number:** ~~TOP-006-1~~

3. **Purpose:**

   ~~To ensure critical reliability parameters are monitored in real-time~~.

4. **Applicability**

   4.1. ~~Transmission Operators~~.

   4.2. ~~Balancing Authorities~~.

   4.3. ~~Generator Operators~~.

   4.4. ~~Reliability Coordinators~~.

5. **Effective Date:** All requirements will be retired on the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements are retired twenty-four months following Board of Trustees adoption.

Deleted: January 1, 2007

B. Requirements

R1. ~~Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use~~.

Comment [Edd1]: Delete – now covered in TOP-002-3.

R1.1. ~~Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use~~.

Comment [Edd2]: Delete – now covered in TOP-002-3.

R1.2. ~~Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use~~.

Comment [Edd3]: Delete – now covered in IRO-010-1, R3.

R2. ~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources~~.

Comment [Edd4]: Delete – now covered in TOP-002-3.

R3. ~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel~~.

Comment [Edd5]: Delete – now covered in PRC-001-1, R1.

R4. ~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern~~.

Comment [Edd6]: Load patterns now covered in the new TOP-005. Remainder not required for reliability.

R5. ~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action~~.

Comment [Edd7]: Delete – now covered in TOP-004-2.

R6. ~~Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations~~.

Comment [Edd8]: Delete – now covered in TOP-004-2.

R7. ~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency~~.

Comment [Edd9]: Delete – RC handled in IRO standards. TOP & BA now covered in certification process and no longer required in standards.

C. Measures

~~**M1.** The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)~~

~~**M2.** Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. (Requirement 1.2)~~

~~**M3.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.~~

~~**M4.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system's near-term load pattern. (Requirement 4)~~

~~**M5.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)~~

~~**M6.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

~~Regional Reliability Organizations shall be responsible for compliance monitoring~~.

1.2. Compliance Monitoring and Reset Time Frame

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance~~.

1.3. Data Retention

~~Each Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.~~

~~Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measure 2.~~

~~Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure 3, 5 and 6..~~

~~Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure 4.~~

~~If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.~~

~~Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,~~

~~The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data~~

1.4. Additional Compliance Information

~~None.~~

2. Levels of Non-Compliance for Reliability Coordinators:

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2:** Not applicable.~~

~~**2.3. Level 3:** Not applicable.~~

~~**2.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**2.4.1** Does not monitor all of the applicable items listed in Requirement 2.~~

~~**2.4.2** Did not have the information specified in R4.~~

~~**2.4.3** Did not bring to the attention of its operators, important deviations in operating conditions and the need for corrective actions. (Requirement 5)~~

2.4.4 ~~No evidence it monitors system frequency. (Requirement 7)~~

3. Levels of Non-Compliance for Generator Operators:

~~**3.1. Level 1:** Not applicable.~~

~~**3.2. Level 2:** Not applicable.~~

~~**3.3. Level 3:** Not applicable.~~

3.4. ~~**Level 4:** Did not inform its Host Balancing Authority and/or the Transmission Operator of all generation resources available for use. (R1.1)~~

4. Levels of Non-Compliance for Transmission Operators and Balancing Authorities:

~~**4.1. Level 1:** Not applicable.~~

~~**4.2. Level 2:** Not applicable.~~

~~**4.3. Level 3:** Not applicable.~~

~~**4.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**4.4.1** Did not inform the Reliability Coordinator and/or other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use in accordance with R1.2.~~

~~**4.4.2** Does not monitor all the applicable items listed in R2.~~

~~**4.4.3** Did not have the information specified in R4.~~

~~**4.4.4** Does not have monitoring to bring to the attention of operating personnel important deviations in operating conditions and the need for corrective actions as specified in R5.~~

4.4.5 ~~No evidence it monitors system frequency. (R7).~~

E. Regional Differences

~~None identified~~.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	TBD	Retired.	Pursuant to changes in Project 2007-03.

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

~~**1. Title:** Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations~~

~~**2. Number:** TOP-007-0~~

~~**3. Purpose:**~~

~~This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.~~

~~**4. Applicability:**~~

~~**4.1.** Transmission Operators.~~

~~**4.2.** Reliability Coordinators.~~

5. Effective Date: ~~April 1, 2005~~ All requirements will be retired on the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements are retired twenty-four months following Board of Trustees adoption.

B. Requirements

~~**R1.** A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.~~

Comment [Edd1]: Moved to TOP-001-2, R9 (redlined version).

~~**R2.** Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.~~

Comment [Edd2]: Moved to TOP-004-2, R1.

R3. ~~A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.~~

Comment [Edd3]: This authority already exists and does not need to be cited in a requirement. .

R4. ~~The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.~~

Comment [Edd4]: Delete as this is now covered in the IROL Project.

C. Measures

M1. ~~Evidence that the Transmission Operator informed the Reliability Coordinator when an IROL or SOL was exceeded and the actions taken to return the system to within limits.~~

M2. ~~Evidence that the Transmission Operator returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.~~

M3. ~~Evidence that the Reliability Coordinator evaluated actions and provided direction required to return the system to within limits.~~

D. Compliance

~~**1. Compliance Monitoring Process**~~

~~**1.1. Compliance Monitoring Responsibility**~~

~~The Reliability Coordinator shall report any IROL violation exceeding 30 minutes to the Regional Reliability Organization and NERC within 72 hours. Each Regional Reliability Organization shall report any such violations to NERC via the NERC compliance reporting process. The Reliability Coordinator shall report any SOL~~

~~violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:~~

~~**1.1.1.** System instability.~~

~~**1.1.2.** Unacceptable system dynamic response or equipment tripping.~~

1.1.3. ~~Voltage levels in violation of applicable emergency limits.~~

~~**1.1.4.** Loadings on transmission facilities in violation of applicable emergency limits.~~

~~**1.1.5.** Unacceptable loss of load based on regional and/or NERC criteria.~~

~~**1.2. Compliance Monitoring Period and Reset Timeframe**~~

~~The reset period is monthly.~~

~~**1.3. Data Retention**~~

~~The data retention period is three months.~~

~~**2. Levels of Non-Compliance**~~

~~**2.1.** The Transmission Operator did not inform the Reliability Coordinator of an IROL or an SOL that has become an IROL because of changed system conditions, and the actions they are taking to return the system to within limits, or~~

~~**2.2.** The Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the system to within the IROL within 30 minutes. (See Table 1-TOP-007-0 below.)~~

2.3. ~~The limit violation was reported to the Reliability Coordinator, who did not provide appropriate direction to the Transmission Operator, resulting in an IROL violation in excess of 30 minutes duration.~~

~~**Table 1-TOP-007-0 IROL and SOL Reporting Levels of Non-Compliance**~~

~~Percentage by which IROL or SOL that has become an IROL is exceeded*~~	~~Limit exceeded for more than 30 minutes, up to 35 minutes.~~	~~Limit exceeded for more than 35 minutes, up to 40 minutes.~~	~~Limit exceeded for more than 40 minutes, up to 45 minutes.~~	~~Limit exceeded for more than 45 minutes.~~
~~Greater than 0%, up to and including 5%~~	~~Level 1~~	~~Level 2~~	~~Level 2~~	~~Level 3~~
~~Greater than 5%, up to and including 10%~~	~~Level 2~~	~~Level 2~~	~~Level 3~~	~~Level 3~~
~~Greater than 10%, up to and including 15%~~	~~Level 2~~	~~Level 3~~	~~Level 3~~	~~Level 4~~
~~Greater than 15%, up to and including 20%~~	~~Level 3~~	~~Level 3~~	~~Level 4~~	~~Level 4~~
~~Greater than 20%, up to and including 25%~~	~~Level 3~~	~~Level 4~~	~~Level 4~~	~~Level 4~~
~~Greater than 25%~~	~~Level 4~~	~~Level 4~~	~~Level 4~~	~~Level 4~~

~~*Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes).~~

~~E. Regional Differences~~

~~None identified.~~

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	TBD	Retired.	Changes pursuant to Project 2007-03.

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A. Introduction

1. **Title:** ~~**Response to Transmission Limit Violations**~~

~~2.~~ **Number:** ~~TOP-008-0~~

~~3.~~ **Purpose:** ~~To ensure Transmission Operators take actions to mitigate SOL and IROL violations.~~

4. **Applicability**

~~**4.1.** Transmission Operators.~~

5. **Effective Date:** All requirements will be retired on the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements are retired twenty-four months following Board of Trustees adoption.

B. Requirements

~~**R1.** The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.~~

~~**R2.** Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.~~

~~**R3.** The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.~~

~~**R4.** The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.~~

Comment [Edd1]: Deleted – now covered by TOP-003-1 for IROL. Taking immediate steps for relief of all SOLs experienced or contributed to may not always be prudent, especially if other organizations are addressing the cause. In such cases, uncoordinated immediate actions may be counterproductive. Accordingly, requiring immediate action to relieve all SOLs was deleted in consideration of TOP-001-1 and TOP-004-2 Requirements applied in combination.

Comment [Edd2]: First sentence moved to TOP-002-1. Second sentence moved to TOP-001, R1. .

Comment [Edd3]: Delete first sentence – bad operating practice, actually eliminates operator flexibility and thus increases risk to the System. Delete second sentence as duplicative of IRO-009-1 as well as FAC-010-1, FAC-011-1, and FAC-014-1.

Comment [Edd4]: Delete – now covered in TOP-004-2.

C. Measures

~~Not specified.~~

D. Compliance

~~Not specified.~~

E. Regional Differences

~~None identified.~~

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** ~~**Operating Personnel Responsibility and Authority**~~

~~2.~~ **Number:** ~~PER-001-0~~

3. **Purpose:** ~~Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System~~.

4. **Applicability**

   4.1. ~~Transmission Operators~~.

   4.2. ~~Balancing Authorities~~.

5. **Effective Date:** 1. All requirements will be retired on the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements are retired twenty-four months following Board of Trustees adoption.

Deleted: April 1, 2005

Deleted:

Deleted:

B. Requirements

~~**R1.** Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System~~.

Comment [Edd1]: This statement is not needed in a reliability standard. The standards already require the necessary actions. The concept of protecting the operator by requiring authorization within a company for him/her to shed firm load is not a reliability requirement.

C. Measures

~~**M1.** The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:~~

~~**M1.1** A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The position description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.~~

~~**M1.2** The current job description is readily accessible in the control room environment to all operating personnel.~~

~~**M1.3** A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.~~

~~**M1.4** Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.~~

D. Compliance

1. **Compliance Monitoring Process**

~~Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the~~

~~authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.~~

~~1.1. Compliance Monitoring Responsibility~~

~~Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.~~

1.2. Compliance Monitoring Period and Reset Timeframe

~~One calendar year~~.

1.3. Data Retention

~~Permanent~~.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

~~**2.1. Level 1:** The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.~~

~~**2.2. Level 2:** The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.~~

~~**2.3. Level 3:** The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.~~

2.4. ~~**Level 4:** The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.~~

E. Regional Differences

~~None identified~~.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	TBD	Retire.	Changes pursuant to Project 2007-03.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Comment Form for 1st Draft of Standards for Real-Time Operations (Project 2007-03)

Comments on the 1st draft of the standards for Real-Time Operations (Project 2007-03). Comments must be submitted by **November 20, 2008**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information:

The Real-Time Operations Standard Drafting Team (RTO SDT) has attempted to eliminate redundancy in the TOP family of standards. As part of this process, the RTO SDT has also made an effort to re-organize the standards and requirements in a more logical manner. In addition, the RTO SDT has supplied a complete set of VRFs, Time Horizons, Measures, and Compliance elements including VSLs. An Implementation Plan has been provided to show the timeframe for compliance.

The Real-Time Operations Standard Drafting Team would like to receive industry comments on this group of standards.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT has deleted the phrase ‘without intentional delay’ from all situations that require specific actions or responses as it was felt that this term is unmeasurable and that operator action and response in a timely manner is part of good utility practice and common sense. Do you agree with this change? If not, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT has eliminated SOLs from TOP-004-2, Requirement R1. The SDT felt that requiring a TOP to operate within all SOLs could effectively reduce the TOPs operational flexibility by eliminating the TOP’s ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time. The SDT determined that operating within each IROL and its IROL T_v was the reliability issue in this requirement. Do you agree with deleting the language about SOLs in TOP-004-2, Requirement R1? If not, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

3. The SDT is concerned about the inclusion of SOL in TOP-001-2, Requirement R5. The SDT thinks that the TOP notifying its RC of every SOL that has been exceeded may create an overload of messages for the RC that does not facilitate preserving reliability. Do you agree that SOL should remain in this requirement? If not, please provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

4. TOP-002-3 Requirement R1 uses the new proposed term Simulated Contingency. The term’s use is intended to clarify that the Contingencies used in the next day assessment are intended to model Contingencies that could occur based on the projected System topology and not Contingencies that have actually occurred on the System. The SDT is concerned that the definition may inadvertently lead the reader to believe that a power System simulator is required. Do you believe that the definition and term accomplish the intention of clarifying TOP-002-3 Requirement R1 without confusing the reading into believing a power System simulator is required? If not,

please suggest alternative wording for TOP-002-3 Requirement R1 that communicates the SDT's intent.

☐ Yes

☐ No

Comments:

5. TOP-004-2, Measure M1: The SDT has adopted the position for this measure and others like it that the absence of an IROL Violation Report is a sufficient measure as opposed to retaining massive amounts of data for later audit. Do you agree with this assessment? If not, please provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

6. The SDT has included VRFs and Time Horizons with this posting. Do you agree with the assignments that have been made? If not, please make specific suggestions for improvement.

☐ Yes

☐ No

Comments:

7. The SDT has included Measures and Data Retention with this posting. Do you agree with the assignments that have been made? If not, please make specific suggestions for improvement.

☐ Yes

☐ No

Comments:

8. The SDT has included compliance elements including VSL for this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for change.

☐ Yes

☐ No

Comments:

9. The SDT has provided an Implementation Plan with this posting. Do you agree with the implementation timeframes? If not, please provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

10. The SDT is recommending retirement of TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0. Do you agree with these retirements? If not, please provide specific reasons for your position.

☐ Yes

☐ No

Comments:

11. If you are aware of any regional variances or any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement that would be required as a result of these standards, please identify them here.

☐ Yes

☐ No

Comments:

12. Are there any other issues that need to be addressed? Please be specific.

☐ Yes

☐ No

Comments:

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Implementation Plan
For Project 2007-03: Real-Time Operations

Prerequisite Approvals

Changes made in this project to TOP-001-2, R3; TOP-002-3, R16, R17; TOP-005-1, R1; TOP-006-1, R1 are dependent on corresponding changes being approved in Project Pre-2006, Operate within Interconnection Reliability Operating Limits:

- IRO-008-1: Reliability Coordinator Operational Analyses and Real-Time Assessments
- IRO-009-1: Reliability Coordinator Actions to Operate Within IROLs
- IRO-010-1: Reliability Coordinator Data Specification and Collection

Changes made in this project to TOP-005-1, R1; TOP-007-0, R4 are dependent on corresponding changes being approved in Project 2006-06, Reliability Coordination:

- COM-001-1: Telecommunications
- COM-002-2: Communications and Coordination
- IRO-001-1: Reliability Coordination – Responsibilities and Authorities
- IRO-002-1: Reliability Coordination – Facilities
- IRO-014-1: Procedures to Support Coordination between Reliability Coordinators
- IRO-015-1: Notifications and Information Exchange between Reliability Coordinators
- IRO-016-1: Coordination of Real-Time Activities between Reliability Coordinators
- PER-004-1: Reliability Coordination – Staffing
- PRC-001-1: System Protection Coordination

Changes made in this project to TOP-002-3, R12 are dependent on corresponding changes being approved in Project 2006-07, ATC/TTC/AFC and CBM/TRM Revisions:

- MOD-001-1: Available Transmission System Capability
- MOD-008-1: TRM Calculation Methodology
- MOD-028-1: Area Interchange Methodology
- MOD-029-1: Rated System Path Methodology
- MOD-030-1: Flowgate Methodology

Revision to Sections of Approved Standards and Definitions

There is one new definition in the proposed set of standards.

Simulated Contingencies – The act of using planning and operating models to replicate Contingency responses that depict the net effect of design considerations.

A mapping table showing the disposition of existing requirements in the affected standards is shown below.

Existing Requirement	New Location
TOP-001-2 (redline version)	
R1	Deleted – The SDT does not feel that this requirement is needed in a reliability standard. Other standards already require the necessary actions. If this statement was intended to protect the operator from liability, it doesn't provide any real protection.
R2	Deleted – The SDT feels that dictating 'immediate action' could be detrimental to reliability.
R3 (re-formatted to R1)	All references to the RC and RC responsibilities have been removed from TOP standards as they are now covered in the revisions being undertaken in Project 2006-06. .
R4	The DP & LSE have been moved into the new R1 in the revised standard.
R5 (re-formatted to R2)	The added phrasing was adapted from TOP-008-0, R3. Deletions were made due to redundancies with TOP-004-3, R1.
R6 (re-formatted to R3)	Retained with changes.
R7 (re-formatted to R4)	Retained and expanded to incorporate sub-requirements.
R7.1 – R7.3	The sub-requirements have been moved into the main requirement in the revised standard.
R8	The first sentence has been deleted due to redundancies with CPS, DCS, and VAR standards. The requirement for real power in the second sentence was deleted as redundant with EOP-002-2, R1 & R6. The requirement in the second sentence for reactive power was deleted since you can't supply emergency reactive assistance remotely.
new R5	This requirement was moved here from TOP-007-0, R1.
new R6	This requirement was moved here from TOP-007-0, R2.
new R7	This requirement was moved from TOP-008, R2.
TOP-002-3 (redline version)	
R1	Deleted as BA only needs to respond to CPS and DCS and thus was not applicable. TOP now covered in new R1 below.
R2	Deleted as good utility practice but unmeasurable.
R3	LSE and GOP are governed by their Interconnection Operating Agreements and therefore not necessary here. TSP deleted as not applicable. TOP covered in new R3.
R4	Deleted as duplicative of proposed IRO-001-2, R1.
R5	Replaced by new R1.
R6	BA deleted as covered in BAL-002-0, R4. TOP covered in new R1.
R7	Deleted as duplicative of BAL-002-0, R1.
R8	Delete as not applicable to BA.
R9	Delete as duplicated in BAL-001 and BAL-002.
R10	Delete as not applicable to BA. TOP covered in new R2.
R11	First sentence covered in new R1. Second sentence deleted as this is now covered in proposed IRO-009-1 as well as FAC-010-1, FAC-011-1, and FAC-014-1. Third sentence covered in new R3.
R12	Deleted as now covered in MOD standards as part of Project 2006-07.

R13	Deleted as verification upon request not seen as needed by this standard. Passed on to Generator Verification team. Data now part of revised TOP-003-1 data specification requirements.
R14	Data now part of revised TOP-003-1 data specification requirements.
R15	Deleted as duplicative of IRO-010-1, R3. Data now part of revised TOP-003-1 data specification requirements.
R16	Data now part of revised TOP-003-1 data specification requirements.
R17	Deleted as duplicative of IRO-010-1, R3.
R18	Deleted as the SDT feels that this is a 'how' as opposed to a 'what'.
R19	Deleted as unmeasurable.
new R1, R2, & R3	New.
TOP-003-1 (redline version)	
R1	This requirement is now covered in the re-worded requirements below for the data specification.
R2	Deleted as now covered in IRO-001-2, R1 (proposed).
R3	Deleted as now covered in.IRO-001-2, R1 (proposed).
R4	Deleted as now covered in Project 2006-06.
R1 through R5 (re-formatted)	New data specification requirements.
TOP-004-3 (redline version)	
R1	Retained with changes.
R2	This is now covered by R1 with the inclusion of IROL and IROL T_v.
R3	This is now covered by R1 with the inclusion of IROL and IROL T_v.
R4	Deleted as unmeasurable.
R5	The first sentence was deleted as unmeasurable. The second sentence was deleted as it is covered by TOP-001-1, R1 & R4.
R6	The first sentence was deleted as it is good utility practice. The second sentence was deleted as all of the sub-requirements were deleted: R6.1 as duplicative of FAC-008 & FAC-009; R6.2 as duplicative of VAR-001-1, R1 for voltage levels and reactive power and real power by R10; R6.3 as it is now covered in new R2; R6.4 as now covered in TOP-002-3, R2.
new R2 (re-formatted)	Rewording of previous requirement.
TOP-005-1 (redline version)	
R1	Deleted – covered by IRO-010-1, R3.
R1.1	Deleted – covered in IRO-010.
R2	Deleted – The SDT did not feel that this was a legitimate reliability concern.
R3	Deleted – now covered as part of the new data specification requirements in TOP-003-1.
R4	Deleted – the PSE does not have any unique information needed by the TOP or BA.

TOP-006-1 (redline version)	
R1	Delete – now covered as part of the new data specification requirements in TOP-003-1.
R1.1	Delete – now covered as part of the new data specification requirements in TOP-003-1.
R1.2	Delete – now covered in IRO-010-1, R3.
R2	Delete – now covered as part of the new data specification requirements in TOP-003-1..
R3	Delete – now covered in PRC-001-1, R1.
R4	Deleted – now covered as part of the new data specification requirements in TOP-003-1.
R5	Delete – covered in certification process and no longer required in standards.
R6	Delete – covered in certification process and no longer required in standards.
R7	Delete – RC handled in IRO standards. TOP & BA now covered in certification process and no longer required in standards.
TOP-007-0 (redline version)	
R1	Moved to TOP-001-2, R5 (redlined version).
R2	Moved to TOP-001-2, R6 (redlined version).
R3	This authority already exists and does not need to be cited in a requirement. .
R4	Delete as this is now covered in the IROL Project.
TOP-008-0 (redline version)	
R1	Deleted – now covered by TOP-001-2, R6 for IROL. Taking immediate steps for relief of all SOLs experienced or contributed to may not always be prudent, especially if other organizations are addressing the cause. In such cases, uncoordinated immediate actions may be counterproductive. Accordingly, requiring immediate action to relieve all SOLs was deleted in consideration of TOP-001-1 and TOP-004-3 requirements applied in combination.
R2	First sentence replaced by TOP-004-3, R1. Second sentence moved to TOP-001-2, R7 (redlined versions).
R3	Delete first sentence – bad operating practice, actually eliminates operator flexibility and thus increases risk to the System. Delete second sentence as duplicative of IRO-009-1 as well as FAC-010-1, FAC-011-1, and FAC-014-1. Some phrasing moved to TOP-001-2, R2.
R4	Delete – now covered as part of the new data specification requirements in TOP-003-1.
PER-001-0 (redline version)	
R1	Deleted - This statement is not needed in a reliability standard. The standards already require the necessary actions.

Compliance with Standard

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DSP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							
TOP-001-2: Coordination of Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X		X
TOP-004-2: Real-Time Transmission Operations	X							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-0: Response to Transmission Limit Violations	Retired							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

The assumption used by the SDT in establishing this Implementation Plan is that the projects mentioned in the prerequisites: Pre-2006, Operate within Interconnection Reliability Operating Limits; 2006-06, Reliability Coordination; and Project 2006-07, ATC/TTC/AFC and CBM/TRM Revisions have been approved prior to the implementation of this Project 2007-03, Real-Time Operations.

Effective Date of Revised Standards
All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

Retirement Date for Existing Standards
All requirements will be retired twenty-four months following the first day of the first quarter following regulatory approval.

Standards Announcement

Two Comment Periods Open

Standards Committee Interpretation Procedure
October 7–November 5, 2008

The Standards Committee has posted a comment form for a 30-day period to gather feedback regarding on its draft procedure for interpretations of standards. The comment period is now open **until 8 p.m. EST on November 5, 2008**.

The Standards Committee wants to revise the process of handling interpretations of approved standards to ensure that requests for interpretation are processed as efficiently as possible, with the objective of getting an interpretation to pre-ballot posting within 90 days from the date of receipt of a valid request. NERC will track the time for processing of interpretations from the date of receipt of a valid request to the date of ballot to provide insight into the effectiveness of this process.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

The status, purpose, and supporting documents for this project — including an off-line, unofficial copy of the questions listed in the comment form — are posted at the following site:

http://www.nerc.com/filez/sc.html

Real-time Operations Standards (Project 2007-03)
October 7–November 20, 2008

The Real-time Operations Standards Drafting Team has posted a comment form for a 45-day period to gather feedback regarding the first drafts of the revised standards and associated implementation plan for Project 2007-03 — Real-time Operations Standards. The comment period is now open **until 8 p.m. EST on November 20, 2008**.

The drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. In addition, the drafting team has supplied a complete set of Violation Risk Factors, Time Horizons, Measures, and Compliance elements including Violation Severity Levels. An Implementation Plan has been provided to show the timeframe for compliance.

- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2 Normal Operations Planning
- TOP-003-0 Planned Outage Coordination

- TOP-004-1 Transmission Operations
- TOP-005-1 Operational Reliability Information
- TOP-006-1 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-0 Response to Transmission Violations
- PER-001-0 Operating Personnel Responsibility and Authority

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Barbara Bogenrief at 609-452-8060.

The status, purpose, and supporting documents for this project – including an off-line, unofficial copy of the questions listed in the comment form – are posted at the following site:

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Shaun Streeter, Standards Program Administrator, at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (27 Responses)
Name (15 Responses)
Organization (15 Responses)
Group Name (12 Responses)
Lead Contact (12 Responses)
Contact Organization (12 Responses)
Question 1 (25 Responses)
Question 1 Comments (27 Responses)
Question 2 (23 Responses)
Question 2 Comments (27 Responses)
Question 3 (24 Responses)
Question 3 Comments (27 Responses)
Question 4 (23 Responses)
Question 4: Comments (27 Responses)
Question 5 (23 Responses)
Question 5: Comments (27 Responses)
Question 6 (22 Responses)
Question 6: Comments (27 Responses)
Question 7 (23 Responses)
Question 7: Comments (27 Responses)
Question 8 (19 Responses)
Question 8: Comments (27 Responses)
Question 9 (24 Responses)
Question 9: Comments (27 Responses)
Question 10 (23 Responses)
Question 10: Comments (27 Responses)
Question 11 (18 Responses)
Question 11: Comments (27 Responses)
Question 12 (25 Responses)
Question 12: Comments (27 Responses)

Individual
test
test
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
No
Group
NPCC
Guy Zito
Northeast Power Coordinating Council
No
Although we agree with the concept and agree that it is unmeasurable, we do not believe that removal of the concept is acceptable and suggest reqording to "as soon as possible but not more than..."
Yes
No
We agree that not every SOL requires communications to another entity. However, there are subsets of SOLs that have the potential to become IROLs or, outside of that subset, left unmitigated, there are other SOLs which will become IROLs. We believe that there should be a requirement to inform the RC when these conditions occur.
No
Change the definition of Simulated Contingencies to: "The act of using planning and operating models to replicate Contingency responses."
Yes
We agree that having evidence of proof for non-events has no value. The focus should be to have evidence of compliance for instances when an event in which compliance was required occurred.
No
TOP-001 - all VRFs but R4 should be HIGH (change R5 and R7). TOP-002 - raise R1 from Low to Medium. It is more than just an administrative requirement.
Yes
NPCC participant members agree provided that only the data specified is required to be dated, not the actual data.
Yes
Yes
No
The note next to R4 in TOP-006 reads: "Load patterns now covered in the new TOP-005. Remainder not required for reliability." We understand that TOP-005 is to be retired, and we are unable to find the new TOP-005 that covers this requirement.
No
No
Individual
Cleyton Tewksbury
Montenay Power Corp.
Yes
No
Yes

Yes
Yes
Yes
No
Group
Santee Cooper
Terry L. Blackwell
South Carolina Public Service Authority
Yes
Yes
No
Notification should be provided to the RC only when an IROL is exceeded. Too much information flowing to the RC could potentially mask a reliability problem.
No
Don't believe the current definition implies that a simulator is required. However, the definition of Simulated Contingency is not clear and very ambiguous. Suggested definition for Simulated Contingency is a contingency evaluated using planning and operating models of the BES.
Yes
Yes
No
OK with the measures and data retention with the exception of our concerns discussed in Question 12.
No
OK with the VSLs with the exception of our concerns discussed in Question 12.
Yes
Yes
No
Yes
TOP001-2 R2 the disconnections prior to switching portion of this requirement. Does this mean the RC and TOPs have to be called prior to switching in emergency situations? (e.g. a line is about to burn down) TOP004-3 R2 what is meant by Agreements in this context? An Agreement is a contract written or verbal. Do Interchange Agreements between TOPs fulfill this obligation? What is meant by synchronous BES tie line and should this be a defined term? Is this just to differentiate between AC and DC tie lines?
Individual
John McCawley
PECO Energy

Group
SERC OC Standards Review Group
Jim Griffith
Southern Co. Transmission
Yes
This phrase is not measureable!
Yes
Although we agree with the SDT's change regarding SOLs, TOPs should not allow an unintended consequence of this change to be less emphasis on resolving or mitigating SOLs.
Yes
We interpret this requirement to indicate that a TOP is required to inform the RC only if action is taken to mitigate an SOL, i.e., if the TOP decides that no action is required for an SOL, the TOP is not required to notify the RC.
No
For additional clarification, we suggest the following alternative wording for the Definition of Simulated Contingencies: "The act of using planning and operating models to model single branch or unit outages in the modeled network."
Yes
No
For TOP-001, R1, R2, R4 - the risk factor should not be the same for each time horizon shown. i.e., for operations planning, same day operations, real-time operations. We suggest R5 should have a Low VRF. For TOP-002-3, the time horizon for each of these requirements (R1-R3) should be "Operations Planning".
No
If the changes suggested above are agreed to by the SDT, please make the appropriate corresponding changes to the measurements.
No
TOP-001, R4. We suggesting changing the words "affect and affected" to "impact and impacted", respectively.
No
The SDT may want to consider a closer implementation date since there are no new requirements included in the proposed revisions to these standards.
Yes
Although we agree with the retirements of TOP-005, 006, 007 and 008, the following discrepancies are noted: Top-006-1, R5 indicates this requirement has been removed to new TOP-005. TOP-005 is being eliminated and a new TOP-005 is not being developed. Where does this requirement reside? or is it really needed? TOP-008-0, R1 indicates this requirement has been moved to TOP-003-1, which is the standard for Operational Reliability Data. Should this read that it has been moved to TOP-004? Per-001-0, R1. We agree with the elimination of this Standard The authority of the system operator is mandated in FERC Order 693, paragraph 112.
Yes
We suggest eliminating R2 of TOP-004-3. An interconnection agreement between two entities will include this requirement.
Individual
Craig McLean
Manitoba Hydro
Yes
Yes
No
As per TOP-004-3, exceeding an SOL does not necessarily put the BES at risk. The SOL for a thermal limit could very well be set for an ambient temperture much higher than the actual ambient temperture. Notifying the RC for such an event would be a waste of resources. We feel it is not necessary to make it mandatory to notify the RC when exceeding a SOL. TOPs should be mandated by a Requirement to document all SOL violations and action taken. Such action may

include but is not limited to: simply further monitoring or making a temporary alarm level adjustment.
Yes
Yes
No
TOP-001-2. Data retention for all requirements should be the same. That is, curent year plus the previous year.
No
TOP-001-2 R5.. SOLs should be removed from the requirement and the VSLs.
Yes
Yes
No
No
Group
PJM Interconnection
Patrick Brown
PJM Interconnection
Yes
PJM supports the deletion and recognizes the problem in measuring "intent".
Yes
The SDT has correctly balanced the need for flexible responses to non-impactive problems.
No
The issue here is in defining what is impactive and what is not. A flow value that creates a temporary overload on a radial line may not be of concern to an RC, thus informing the RC that the flows are under the limit is merely a distraction. During Emergency Conditions such non-relevant information can be more then distractive it can needlessly tie up people to the point of causing those people to overlook real problems. The standard could be written to include a requirement that the RC must inform the TOP of any overloads that it, the RC, requires to be informed of. Then the TOP is obligated to provide information about the critical SOLs and mandated to report on the relief of every SOL.
No
The definition needs more work to avoid confusion. The word "simulated" will itself likely be a point of contention. One solution would be to delete the word "simulated". If this issue of post-contingency simulation becomes a problem, then a Standard Interpretation can be issued.
Yes
No
TOP-001 - all VRFs but R4 should be HIGH (change R5 and R7) TOP-002 - raise R1 from Low to Medium some type of OPB assessment is required, it is more then just an administrative requirement.
No
TOP-003 M1-M5 - they all introduce a new requirement (i.e. the the report be dated) - that requirement should be dropped from the measures.
Yes
Yes
Yes
No
No

Individual
Scott Berry
Indiana Municipal Power Agency
Yes
TOP-003-1 Requirement 4. Entities are to provide data, as specified in R1, to their Transmission Operators. Does R1.2 (mutually agreeable format) cover the entities who are reporting data to their Transmission Operators? If the request for data is not done on a regular basis, the entities in R4 need to receive a proper request from the Transmission Operator and be given time to gather the data. Neither R1 or R4 clearly address this process and the standard should address how the entities in R4 will be made aware of any specification of data needed by the Transmission Operator or Balancing Authority.
Individual
Jianmei Chai
Consumers Energy Company
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
No
Individual
Kirit Shah
Ameren
Yes
Yes
This change is consistent with the fact that BES operation is a risk-based endeavor. While IROL risk is so severe it is unlikely to be properly evaluated by a TOP, SOLs should be considered as

part of the normal risk assessment.
No
This has proven to be a duplicative effort since the RC is monitoring the facilities also. Change the text to say, "to the extent that the RC does not have systems in place, the TOP will â€¦.".
No
This change is not necessary. The "Contigency" definition is for things that could but are not certain to happen. Obviously, there is no basis for a contingency that has occurred. Once occurred, it is an event.
Yes
An absence is sufficient.
Yes
No
There are inconsistencies in specified retention periods among several requirements. While we do not know the reason for this, we recommend that the SDT review the different retention periods and provide as much consistencies as possible.
No
1. For the TOP-001-2 VSLs for R4, what if the TOP or GOP does not coordinate because of system conditions. Is it possible that those entities might disagree as to what is a system condition? How would this disagreement be handled? 2. For the TOP-001-2 VSLs for R6, the timing is only one element of the evidence. These VSLs should be rewritten because the VSLs add to the requirement. The VSL should be changed to replace "the timing of when it acted" with "its actions" plus, add the text "when it" between the words "or" and "directed others".
Yes
Yes
No
Yes
Standard TOP-004-3, section "1.5 Additional Compliance Information" - should this be included in R1/M1? Why is there a separate section at the end?
Individual
Darryl Curtis
Oncor Electric Delivery
Yes
Yes
Yes
No
"Study Contingency" may be a better choice and would remove the possible link between simulator and simulated contingency
Yes
Yes
Yes
Yes
Yes
Yes
No
No

Group
Dominion - Electric Market Policy
Louis Slade
Dominion Resources Services, Inc
Yes
Yes
Yes
Suggest revising R5 to read "Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when a reportable SOL (as identified by its Reliability Coordinator)has been exceeded. Suggest revising R6 to read "The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROLâ€™s Tv and shall inform its Reliability Coordinator of such actions.
No
We suggest revising the stated purpose rather than creating a new definition. We suggest revising purpose to read " To ensure that reliability entities have coordinated plans for meeting expected operating conditions including contingencies that could occur based on projected system topology."
Yes
No
TOP-001-2 We believe that R5 and R7 warrant high VRF. TOP-002-3 R1 warrants something higher than low. How can the TOP meet the intent of R2 (VRF = high) if it has failed at R1? We suggest that R1 and R2 should be high. R3 should be reduced to low since the RC is required by IRO-004-1 @R3 to develop action plans in conjunction with its TOPs. The heavier burden should be placed on the RC. The time horizon for R1-3 should be changed to Operations Planning
No
TOP-001-2 @M4 - We don't agree with the underlying requirement (see comment to question 12). We do not agree with data retention requirements for M1 and M3 this standard. In our mind, there are two tenants that must be honored above all. The first is to follow reliability directives whenever possible, the 2nd is to provide data necessary for reliability assessments. Where an entity fails to comply, the requestor should immediately file a complaint with the region or NERC. We expect either of these to perform a prompt review. So, we don't see the need to keep data for a year nor do we see value in keeping data until next compliance audit when found non compliant. TOP-002-3 @ M3 should be removed as we do not agree with underlying requirement (see comment to question 12).
No
TOP-001-2 R1 - Could be interpreted that non-compliance is based on number of occasions whereby entity invoked safety, equipment, regulatory, or statutory requirements as opposed to number of occasions whereby entity failed to comply with reliability directives. Suggest revising to read "â€¦.did not comply with reliability directives issued by the Transmission Operator and did not inform the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, on one occasion." Suggest use of similar language for each Severity Level. R3 - Suggest revising to read "The Transmission Operator, Balancing Authority, or Generator Operator did not render emergency assistance to others, as requested and did not inform the requestor that such actions would violate safety, equipment, regulatory, or statutory requirements. R4 - Revise to conform to comment in question 12. TOP-003-1 R4 - Do not agree that a any failure to provide data warrants severe. Is reliable operations jeopardized for failure to report an outage on a 10 Mw peaking CT as it is for a 1000 Mw base load unit? We don't see them as the same and would rather see something akin to the following: Low - Failed to provide > 25% of data required Moderate - failed to provide 26-50% of data required High - Failed to provide 51-75% of data required Severe - failed to provide > 75% of data required
Yes
While we agree with the SDT that all prerequisites must occur prior to implementation of this plan, we wish to cite, for the record, the sheer volume of draft standards that are now 'dependant' for prerequisite action on preceding drafts. We would like to see a moratorium on new drafts until the current back log is cleared. We are concerned that new drafts are being reviewed with the potential that ramifications of underlying/preceding drafts aren't being fully understood and/or that modifications made to any such drafts may not follow through in later draft standards predicated upon them.
No
We believe that the existing standards are more clear those contained in this draft. This draft

seems to be trying to delineate TOP and BA standards/requirements from RC standards/requirements. In doing so, the draft loses the feeling of cohesiveness of the existing standards.
Yes
Typically, GO, GOP, PSE, LSE entities are prohibited from by federal and/or state Standards/Codes of Conduct from access to much of the information that would be required to perform any type of 'reliability assessment', determination of criticality or adverse impact. Only entities such as the RC, TO, TOP and perhaps BA have access to all the necessary information to make such determinations. For the GO, GOP, PSE, LSE entities, any such determination is really a business risk assessment, not a reliability assessment.
Yes
Generic comment - There appears to be a hieracy created by Reliability Standards with the RC being highest, followed by (equally?) the BA and TOP. If this is true, we'd prefer that the RC identify requirements necessary to enable it to meet its requirements under the standards. As new standards are being created, there appears to be the potential for some entities to have to provide the same information or have to coordinate actions with multiple entities but at different times, using different protocols. As examples: IRO-002-2 already requires the RC "to determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability Coordinators." EOP-002-2 states "A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load." In order to meet this requirement, the BA will likely have to request GO/GOP to provided unit availability data (outages, derates) and the DP, TOP and/or LSE to provide load projections. This same information will likely be needed (and required) by the RC to peform its assessments. In this project TOP-001-008@ R4 states "Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to affect other reliability entities." and TOP-003-1@ R4 requires entities to provide data, as specified in Requirement R1, to its Transmission Operator(s). If these entities have provided the information required by their respective RC and the RC is required to coordinate with other RCs (IRO-014-1) there appears to be duplication which increases the workload of each entity and introduces opportunity for miscommunication or what may appear to conflicting submission of data (assuming that format and timeline differ). Specific comments TOP-001-2 R3 - concern about ambiguity of phrase "to others", particularty from the GOP perspective. For reliability standards, the GOP should only be required to provide such assistance when so requested by its RC. Any other obligations should be included in the terms and conditions of its Interconnection Agreement with the TO or DP and, as such, is outside the scope of these standards. R4 - Concern about phrase "coordinate its respective operations known or expected to affect other reliability entities with those entities", particularly as it applies to GOP. GOP doesn't have access to data, nor the expertise, to make reliability assessments and may be precluded by Codes/Standards from coordinating with other entities. Suggest revising to require GOP to provide data as required by its RC to perform reliability assessments. Since GOP has to follow emergency directives issued by RC or TOP, there is nothing for the GOP to coordinate. If GOP actions or planned actions are deemed to have the potential to result in adverse impact to reliability, the RC or TOP should issue a directive to GOP to cancel such actions. TOP-002-3 - R3 should be deleted given that IRO-004@R3 states that "Each RC shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs." TOP-003 R1.2 - Am concerned about the term "mutually agreeable format". Does the phrase 'mutually agreeable' apply to ALL applicable entities, or just the TOP and BA? Aren't there enough protocols and tools currently in existence (SDX, ICCP, RCIS) that the standard could at least address use of existing formats as opposed to 'mutually agreeable'? R4 - Does not require entities to provide data to BA although R1 requires BA to "â€¦have a documented specification for dataâ€¦.." and R3 requires each BA to "distribute its data specification to entitiesâ€¦". We suggest revising R4 to read "Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator and Balancing Authority." We removed the plural indicator as we believe that each entity's facility can be in only one TOP and BA area. If information relative to that facilty is needed by multiple TOPs or BAs, those entities should share information. The entity should not be required to submit data for the same facility to multiple reliability entities.
Individual
Will Franklin
Entergy System Planning & Operations (Gen & Mktg)
Yes

No
The RC should be aware of SOL exceedances in order to perform their function and maintain situational awareness.
Yes
The definition of "Simulated Contingency" provides enough clarity to avoid confusion.
Yes
Yes
Yes
The Implementation Plan refers to items in other proposed standards that will take the place of existing requirements, some of which are referred to by project number and others by standard number. In either case, the proposed standard that will contain the requirement should be presented or easily referenced. for example the propose IRO standards that will accommodate requirements moved from the TOP standards are not available for review and confirmation. Also, several requirements were deleted because they were "immeasurable". Some of these items should be revisited and determined if an alternative "measurable" requirement can be drafted. For example, it is important that an entity not continue operate in an unknown operating state (TOP-004 R3) and promptly return to an analyzed conditions/or perform an analysis for the current condition.
Individual
Edward J Davis
Entergy Services
No
There is merit in holding entities accountable for making timely notifications,etc. Would an entity be compliant if they waited 6 months to notify the TOP of changed in Real Power capability? Perhaps the measures can be worded such that proof of the event's time and proof of the notification's time are not significantly different. However, we suspect that entities for which the requirement is applicable would WANT guidance on what is timely and what is not. Leaving that much up to the interpretation of audit teams is not very desirable.
Yes
We agree as this was the original intention of the NERC OLDTF that first developed the terms SOL and IROL.
No
SOLs should be removed. While certain SOLs may need to be communicated to the RC per internal processes, only IROLs should be required to be reported. Reporting of every SOL could "water down" the communications to the RC and add confusion when IROLs are reported.
No
There can be much confusion with the standards when terms are used in multiple ways. The poster child for this is "critical facilities." I agree with the intent of the SDT, but suggest the term "Postulated Contingencies."
Yes
No
TOP-002-3 R1: VRF should be Medium since you can't do R2 or R3 without it. TOP-003-1 R5 - VRF should be Medium, the same as R4
No
TOP-002-3 M1: We suggest a good example of compliance evidence be power flow models and study results instead of operator logs. If not, what does "assessment" mean in R1?
Yes
Yes

No
Yes
Please expound upon the reasons why the SDT determined that TOP-002-2 R19 and TOP-004-2 R4 are unmeasurable. TOP-001-2 R4 is going to be very difficult to measure. Any guidance the SDT can provide on how to demonstrate compliance would be appreciated. TOP-002-3 R3: The requirement that was mapped to this in the implementation plan used the phrase "shall coordinate." We think that R3, as written, is too vague. Also, it is more command and control versus a collaborative effort as implied by the previous use of "coordinate."
Group
Southern Company Transmission
Roman Carter
Southern Transmission
Yes
Yes
No
Requirement 2 of TOP-001-2 already contains a provision for the TOP to inform its RC of real-time or anticipated emergency conditions. If a particular SOL is considered an emergency condition, then it would be reported. Otherwise, it is not required. Therefore, we agree that notifying the RC of every SOL is not necessary.
No
The proposed definition of â€œSimulated Contingencyâ€ is not clear. Also, it is not apparent why a new definition is even needed. Make the definition part of the requirement. Why couldnâ€™t â€œSimulatedâ€ be replaced with something like â€œdepictedâ€, â€œrepresentedâ€ or â€œportrayedâ€. Possible wording for the Requirement 1 might be â€œThe Transmission Operator shall have an assessment for the next dayâ€™s operation that indicates whether it will exceed any of its System Operating Limits (SOLâ€™s) during anticipated normal conditions and Contingency events represented through planning and operational analysis models reflecting design parameters and system conditions.â€ In the event the drafting team does not agree to implement our suggested change above, the drafting needs to address this issue also in IRO-004-01, R1 where the requiement states normal or anticipated contingency events and not "simulated events". The two requirements should be consistent in terms.
Yes
Yes
Yes
Yes
No
Both TOP-001-1, R1, and PER-001-0, R1, were deleted. These standard requirements require operating personnel under the TOP and BA to have the responsibility and authority to implement real time actions to ensure the stable and reliable operation of the bulk electric system. Additionally, in paragraph 1330 of FERC Order 693, FERC approved PER-001-0 as mandatory and enforceable. Accordingly, FERC is clear in its intention that the operating personnel of the TOP and BA have authority to take action without any managerial approval being required. Also, in paragraph 1582 of the Order 693, FERC states R3 of Reliability Standard IRO-001-0 establishes the decision-making authority of the reliability coordinator, but not operating personnel of the TOP or BA. These facts stated above could be exposing a reliability gap if this standard is approved as written because the entities performing the TOP and BA functions must have the support of a NERC standard to be able to take immediate action without management approval or intervention. Reliability Standards Compliance programs are based on abiding by the NERC standards. By the TOP and BA not having clear decision-making authority from a NERC standard could lead to senior management of a company stepping in and requiring their approval before operating personnel are allowed to take action to alleviate problem. This could lead to jeopardizing reliability. ï€ TOP-001-1, R2 has been deleted. It would seem logical that a requirement for the TOP to take immediate action to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc., would be worthy of being kept in the

standard. If it is a duplication of an existing requirement, then please reference where the duplicate requirement is located. ï€ Under TOP-001-2, R2 the phrase "including potential impacts caused by disconnections prior to switching" was added to the requirment. This addition seems to provide too much specificity and provides a very granular view for the requirement. It is best to remove this phrase and bring the requirement back to a higher level and end the sentence after "emergency conditions". ï€ It was noted that TOP-001-2, R3 replaces TOP-001-1, R6 and that the following component of the old R3 was deleted: "provided that the requesting entity has implemented its comparable emergency procedures". For an entity to render emergency assistance to another entity who has not implemented their own internal company emergency procedures prior to seeking help from others is not a wise decision. Deleting this phrase would create a burden on others providing the emergency assistance. Unless it can be shown there are other standard requirements already containing this required action, we recommend NOT removing this phrase. ï€ Removal of the BA from requirement (TOP-002-2, R1) to plan operations into the future is not appropriate. Although it is agreed that CPS and DCS are much of the real-time basis for reliable operation, due to the physical requirements to start or even change output of many units, it is absolutely necessary that the BA plan a near-term operating horizon of several hours so that DCS and Energy Emergencies can be avoided. Removing the requirement for the BA to plan because DCS covers everything would be like removing the requirement for TOP to plan and just rely on the fact that the TOP has to correct SOLâ€™s and IROLâ€™s under TOP-004-1, R1 without any planning. Also, without this requirement to plan, under what basis would the BA have to request the generator output planning information currently in TOP-002-2, R15 that the SDT says will become part of TOP-003-1 data specifications? The Generator Operator could say there is no need for the BA to plan beyond what is needed for DCS and CPS and thus claim such requests are not needed. By removing this requirement the SDT has removed any basis for doing near-term planning. ï€ Similarly to the comment above for R1, the BA has a need to plan for the items covered in TOP-002-2, R5. Such a requirement should be included in the new R1 of TOP-002-3. ï€ TOP-002-2, R8 requires the need to plan to meet Interchange Schedules and ramps, and should be carried forward to TOP-002-3. Even though INT-006 requires the BA to consider ramping capability in approving/denying Arranged Interchange, generation dispatch and unit capability can change significantly after an Arranged Interchange is approved. The BA must consider (i.e. plan) near-term ramps in being able to meet an upcoming Interchange ramp. The result of not planning for a ramp that can no longer be met is a frequency deviation. The ability to ramp is not a parameter in the BAL-001 and BAL-002 standards. ACE is the basis for BAL-001 and BAL-002 and ramping capability is only one contribution to ACE and thus those standards should not be used as a reason for removing this requirement. In addition, the CPS criteria of BAL-001 are not granular enough (CPS1 is 12 month rolling average and CPS2 is a calendar month number) to manage real-time issues that can cause reliability problems. ï€ In the new TOP-003-1 which addresses reliability data needs, R2 and R3 require distribution to entities â€œthat provide Facility statusâ€. Why is the term â€œstatusâ€ used? Why would not the distribution be to any entity that is the source of data under the specification R1 and not limit it to a â€œFacility statusâ€ source? ï€ In the mapping table of the Implementation Plan, TOP-006-1 R5, R6 and R7 were deleted with a reason given by the SDT that the monitoring activities are covered in the certification process. It is unclear how a one time verification of the activity during certification translates into a requirement that the monitoring processes continue â€“ and more importantly that violations have a penalty. It is recommended that these requirements be retained (and perhaps others deleted added back as well). ï€ Under TOP-004-3, R2 states that Agreements between TOPs are required for switching of BES tie lines. It is felt that this type of detailed information would be contained in the Interconnection Agreements between the two parties. Only when there are not existing Agreements in place would this requirement be necessary. In those cases where it is necessary, it is recommended that "specify switching" be replaced with "specify the procedures for switching". ï€ Under TOP-003-1, R4, the Balancing Authority should be added along with the Transmission Operator as receiving data as specified in R1. Requirement 1 requires the TOP and BA to have documented specification for data, and R4 requires the responsible entities to provide this data only to the TOP. If the BA is required to have the documented specification for data support, then the responsible entities should be required to provide appropriate data not only to the TOP but to the BA as well.

Yes

In the purpose statement the term "functional entities" is used. The term creates a confusion of terms between the purpose statement and requirements. Requirements 4 and 7 call for coordination among "other reliability entities" and "reliability entities" respectively. Therefore, recommend replacing "functional" with "reliability". The limits mentioned in TOP-001-2,R5 need more description. The recommended change is as follows: â€œEach Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within the IROL limits when an IROL or SOL has been exceeded.â€ Requirement 7 of TOP-001-2 is duplicative as it applies to the TOP to that of standard IRO-005-2, R13. Could this result in a double jeopardy for non compliance with this requirement? In TOP-003-1, in the Purpose statement replace "system" with "System". In R1 of TOP-003-1, it is recommended that the term "specification" throughout the standard be replaced with a better term to describe what is meant in the standard. For example, the word "catalog" may be a better term. Also, it recommended that in the sub-bullet R1.3 the word "providing" should be replaced with "exchanging". In TOP-001-2, In section 1.4 of Data Retention the term "reliability entities" is capitalized. Should it be in lower case? On several requirements (e.g., TOP-006-1, R1;TOP-008-1, R1) recommended for retirement, there is a comment in the redline version stating that the requirement is covered in another standard. Upon reviewing the other standard, the requirement was not found. Was the latest version of the standard posted properly on the NERC website?

Individual

Dan Rochester

Independent Electricity System Operator

No

This phrase should not be removed. If measurability is required, similar language ("without delay") in R4 of the recently approved IRO-009 standard should be used, with a condition to assess if there was a 5 minute delay for assigning a High VSL.

No

We strongly disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating th TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time." SOLs are detemined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability? Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? We are also very concerned that R1/R2 in TOP-002 requires the TOP to assess potential exceedence of IROLs only but not SOLs. This sends a the wrong message to the industry that TOPs do not need to plan their operations to within established SOLs. So why do we mandate the TOPs to calculate SOLs to begin with? We feel strongly that R2 in TOP-002 should be revised so that it includes as part of the requirement, preclusion of operating in excess of any SOLs. We believe that completely removing SOLs from the requirement is contrary to the long-term objective of enhancing reliability. Further, we believe that all SOLs should be respected in the planning time-frame and in real time with the exception of low likelihood or rare circumstances. We do recognize that there are instances where post-contingency, a TOP may not be able to respect its repreparation limits for the next contingency. Those instances must however be limited to situations in which, after applying available means to eliminate the violation short of firm load shedding, and where it can be demonstrated that the SOL violation cannot propagate into an IROL violation following the next worst contingency. That is, the repreparation limit is non-impactive to the BES. We need only recall that some blackout events started by exceedence of local area limits (SOLs). When sufficient events occur (such as when a line rating is not observed or its overload not corrected), cascade overloading on another transmission line and yet another transmission line and so on may occur. An apparently non-impactive SOL, if not observed and whose exceedence not corrected, can result in cascading outages.

Yes

SOLs are intended to ensure reliabile operation of the BES. TOPs, who calculate these SOLs to begin with, shall not intentionally operate its system to be very near or exceeding SOLs. Thus, we do not expect SOL exceedences to occur so frequently that reporting to the RC will create an overload of messages.

No

We do not see the need to define this new term. Further, the definition is inaccurate (mixing contingency which is a "what-if" event with system response) and confusing (we are unable to understanding the meaning of "the net effect of design considerations" in an operational planning assessment domain. Having said that, we do not interpret the term to mean the requirement for a "simulator". To eliminate the concern of misinterpretation, we suggest that R1 be reworded to "â€¦ during anticipated normal conditions and analyzed contingency events."

No

First of all, we do not agree with the removal of SOL from R1 so we do not agree with M1. On the approach the SDT is proposing, we do not agree with the rationale that the absence of an IROL violation report is a sufficient measure. We believe the TOP should be required to provide evidence to demonstrate compliance (in this case, the data showing operating within IROL and Tv).

No

TOP-001 R1: We do not agree wth a High VRF. Not complying with the TOP's directives does not

necessarily result in cascading outages or instablility. And since the responsible entities are allowed to not comply with the directives for safety and other reasons, we are unable to ratioanlize how impactive a risk can be when an entity violates this requirement. R2: We are unable to assess the VRF for this requirement since we do not understand the meaning of "â€¦.potential impacts caused by disconnections prior to switching." R3: We do not agree with a Hgh VRF for the same reason as for R1, viz. if provisions for not complying is given, how high a risk it is if a responsible entity violates this requirement? TOP-002 R1: We suggest raising the VRF for R1 to a Medium. Day ahead operationL assessment of system conditions against established limits is essential in ensuring sufficient resources are available and operational plans are in place to prevent exceeding limits and to provide mitigating measures when such exceedence occurs. This assessment uses established limtis and as such, is equially impactive, if not more impactive, than developing the limits themselves. TOP-003 R5: We do not agree with a Low VRF assigned to this requirement whose intent is essentially the same as R4 except R5 goes beyond the local TOPs and BAs to the adjacent or higher level entities, which also need this data to ensure reliable operation. We suggest this VRF should be Medium - the same for R4.
No
We do not agree with some of the requirements (see above) and hence do not agree with some of the Measures. Other than that, we generally agree with the measures and retention periods for those requirements that we agree with.
No
a. We do not agree with some of the requirements, and suspect other commenters may express disagreements with some requirements. This may result in changes to the requirements and as such, the VSLs will need to be revised. b. A number of the VSLs proposed in the TOP standards, e.g. TOP-001, R1 and R2, are graded according to the number of repeated violations. This approach may need to be changed since recent FERC NOPR proposes that repeated violation is not to be the basis for different violation levels. c. TOP-003, R1: It appears that missing one of the subrequirements is assigned a Low VSL, missing 2 of them is assigned a Medium VSL and missing all 3 or having no documented specification is assigned a Severe. We suggest to move the first 2 conditions to Medium and High.
Yes
We generally agree with the implementation timeframes that are dependent on the implementation of other standards. However, we reserve judgment on any specific issues that may arise when more definitive dates are proposed.
No
The note next to R4 in the red-line version of TOP-006 says: "Load patterns now covered in the new TOP-005. Remainder not required for reliability." Since TOP-005 is to be retired, we are unable to find a new TOP-005 that covers this requirement. Please explain the relevance of this note.
No
No
Individual
Greg Rowland
Duke Energy
Yes
Yes
We agree with the SDT's logic in eliminating SOLs from TOP-004-2 Requirement R1.
Yes
R5 should be revised to also require the TOP to notify the RC of the particular IROL or SOL that has been exceeded.
No
We believe that the definition of Simulated Contingencies should be revised as follows: The act of using planning and operating models to model single branch or unit outages in the modeled network.
Yes
Yes
Yes
No

TOP-003-1 Requirement R5 VSLs should be patterned after the VSLs for Requirements R2 and R3, i.e. a graduated scale since R5 is not a binary requirement. TOP-002-3 Requirement R3 - if only one reliability entity is identified in plans to preclude exceeding an IROL, and that entity is not notified, which VSL would apply - "Lower" or "Severe"?
Yes
Yes
TOP-005-1 Requirement R2 has been deleted because it is not a reliability concern. Has this requirement been picked up in NERC Rules of Procedure or business practices? TOP-006-1 Requirement R4 is being deleted, and the comment says that load patterns are covered under TOP-005. But TOP-005 is also being deleted - is it intended that load data will be covered by TOP-003 now?
No
Yes
TOP-001-2 Requirement R4, Measure M4 and VSLs for R4 : What does the word "affect" mean? Any operation by a TO or GO could have a slight affect on other reliability entities. The word "affect" should be qualified in some manner, to avoid a requirement to coordinate operations with negligible impact. We suggest using the phrase "have a reliability impact upon" instead of the word "affect". TOP-004-3 Requirement R2, Measure M2 : What does "specify switching" mean? We suggest this wording be removed from the requirement. This requirement may have been moved from TOP-004-1 Requirement R6, but it is unclear. TOP-008-0 Requirement R1 is being deleted. The Comment says that this is now covered by TOP-003-1, and in consideration of TOP-001 and TOP-004 requirments in combination. We think the Comment should not reference TOP-003-1. TOP-002-2 Requirement R11 contains a requirement for a seasonal assessments to determine SOLs. Where is this requirement in the revised standards?
Group
Bonneville Power Administration
Denise Koehn
Transmission Reliability Program
Yes
Yes
No
Agree that it would increase workload while trying to return the system within limits. This requirement should probably move to TOP-004-3. R6 should maybe move there also as Real-Time Operations?
No
Change the definition from "design considerations" to "planned outages".
Yes
SDT has cleaned up TOP-004-3 well, removing duplicate requirements from other standards. I don't believe R2 (Agreements of switching) is necessary since TOP-001-2 R3 appears to cover assisting to mitigate emergencies/IROLs. It seems to me TOP-001 R5 and R6 are also real time operations and should go to TOP-004-3 has R2 and R3.
Yes
Yes
Yes
I think TOP-001-2 R6 would be better to say the TOP "shall act to ensure mitigation of the magnitudeâ€¦" thus eliminating extraneous phrasing "direct others".
Yes
Yes
Yes
WECC TOP-STD-007-0 would now need to link to TOP-004-3 (R1).
Yes
Good Ideas - thanks. However, do not see anything analogous to the current TOP-001 R1. and think we should retain something of this nature.

Group
Midwest ISO Stakholders Standards Collaborators
Jason Marshall
Midwest ISO
Yes
Intent is an enforcement issue. Thus, it does not belong in the standard.
No
The TOP should be required to operate within SOLs. SOLs by definition can by be voltage or stability limited. SOLs, if exceeded, can be become IROLs. What in the standards will ensure that the TOP is sure the exceeding the SOL will not result in an IROL. The situation described in the question may not even require that an SOL be defined. No where in the standards is there a requirement that every thermal limit must be encompassed in a SOL. If a TOP decides to "ride" out an SOL rather than mitigate the violation, in reality the TOP has indicated that the current SOL is invalid. Why can't the TOP just determine what the new SOL is?
Yes
We believe that the TOP notifying the RC of every SOL that has been violated does not create an overload messages. The TOPs in the Midwest ISO reliability footprint already notify the RC of all SOL violations and we have not found it to be a burden. In fact, we have found it actually improves operations because it causes the RC to continuously validate the results of the real-time contingency analysis against the TOPs. We do believe that the requirement should not be prescriptive to require a particular type of communication such as via the phone. To a certain degree this requirement can be met by simply having redundant models and contingency analysis in the EMS. We observe that the requirement is not for the TOP to notify the RC every time that an SOL is violated. In fact, the requirement is only to notify the RC of the actions to be taken. Thus, if no actions are taken, the TOP does not have to notify the RC. We believe the language should be strengthened to clarify that the TOP should notify the RC everytime an SOL is violated even when no mitigation is taken.
No
Why can't you just use the term potential in front of Contingency?
Yes
Individual
Thad Ness
AEP
Yes
Yes
The purpose statement in TOP-004-1 is consistent with the IROL NERC defined term. We suggest keeping the original purpose statement from TOP-004-1. If SOL are to be reported then some prioritization needs to be given. We suggest reporting the largest SOL if there are several common to an area of congestion.
Yes
The TOP-001-1 purpose statement deals with emergencies and taking actions to resolve them. The TOP-001-2 purpose statement deals with coordination. We concur that notifying the RC of every SOL violation could be overwhelming and counter productive to reliability. If SOL are to be reported then some prioritization needs to be given. We suggest reporting the largest SOL if there are several common to an area of congestion.
No
The "Simulated Contingency" definition lacks clarity and its use in TOP-002-3 R1 does imply that an offline load flow program would be required when conducting a next day assessment. Suggested wording: Replace "and Simulated Contingency" with "and/or potential contingency".
No
Refer to question 3 response. The TOP-001-2 three year data retention for SOL violations seems

excessive. Data that has been retained this long tends to lose its value. We would like to hear an argument from the SDT how this improves system reliability. Similarly, the three year data retention for distributing data specifications in TOP-003-1 (R2/M2, R3,M3) also seems excessive. We propose that the current and previous calendar years would suffice.
Yes
Yes
Yes
The intent of TOP-004-03 R2 requires some clarification. It seems unnecessary to have an agreement for switching every BES tieline. It seems unlikely that every conceivable situation for switching a tieline could be covered in any type of agreement.
Group
FirstEnergy
Dave Folk
FirstEnergy
Yes
Yes
No
However, the SDT should develop rules that will drive the reporting of incidences where entities exceed SOLs on a regular basis. As an example: the operating studies show that the facility emergency thermal limit is expected to be exceeded by 25% for 4 consecutive hours of 5 consecutive operating days. The goal should be to flag instances where SOLs are exceeded on a regular or routine basis in an effort to highlight situations where mitigation actions or system reinforcement projects may be needed or required to preserve the reliability of the BES.
No
We believe that the definition is not needed and that the use of the word "simulated" in and of itself provides sufficient clarity that the requirement does not refer to actual Contingency events. The premise of the requirement is an assessment of "next day" system condition so it is unclear how this could in anyway be construed to be an actual contingency event. However, what is not clear in the requirements is what type of contingencies are to be evaluated? Is it single Contingency (N-1) events only. What if bus faults were not studied would there be a potential for non-compliance? There should be some tie to the TPL standards to specifically identify which Contingencies must be evaluated for Next Day analysis.
Yes
No
The VRF for TOP-001-2 R7 should be a "High." Failure to follow the most conservative limit in times of uncertainty could negatively impact real-time reliability. The VRF for TOP-002-1 R4 seems inconsistent. It has a qualifying concept of urgency of time in the phrase "â€¦ unless System conditions do not permit such coordination." which implies critical to the reliability of the BES yet it has been assigned a Medium VRF. Also, failure to coordinate an action may not always result in an impact on the BES, but the action does in theory bear a risk to the reliability of the BES. This VRF should be a High. The VRFs for TOP-002-3 seem inconsistent. Requirement 2 which requires planning to mitigate a potential IROL discovered in the study required under R1 has a High VRF while R1 which requires the study be done has a Low. It is difficult to understand how a source requirement such as R1 can have a lower VRF then a derivative requirement such as R2. R1 and R2 should both have Medium VRFs since they are planning in nature and do not have an immediate impact on the BES. The VRF for TOP-003-1 R4 and R5 seem inconsistent. The drafting team appears to consider it a Medium risk for an entity not to supply operating data to its Transmission Operator, but a Low risk for that Transmission Operator not to supply the operating data to an entity "with immediate responsibility for operational reliability." The VRF for R5 should also be a Medium.
Yes
No
The VSL for TOP-001 R1 should all be revised to state, "â€¦ The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, and the respective entity failed to inform the Transmission

Operator that such actions would violate safety, equipment, regulatory, or statutory requirements on (one, two, three, four or more) occasion." The VSL for TOP-001 R3 should be revised to state, "The Transmission Operator, Balancing Authority or Generator Operator did not render emergency assistance to others, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements. The VSL for TOP-001 R4 should be revised in a similar fashion to R1 and R3 above. The VSL for TOP-002 R3 as written implies that an entity that interacts with only one reliability entity would not receive a violation greater than "lower." In addition, as written these VSLs seem to allow the Compliance Auditor the opportunity to choose how to apply the VSL. As an example the entity with one reliability entity could be found to be guilty of a "Lower" violation because they missed their one reliability entity or they could be guilty of a "Severe" violation because they missed 100% of their reliability entities. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity. The VSL for TOP-003 R2 as written implies that an entity that interacts with only one data supplier would not receive a violation greater than "lower." In addition, as written these VSLs seem to allow the Compliance Auditor the opportunity to choose how to apply the VSL. As an example the entity with one data supplier could be found to be guilty of a "Lower" violation because they missed their one data supplier entity or they could be guilty of a "Severe" violation because they missed 100% of their data supplier entities. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity. The VSL for TOP-003 R3 has the same problem as R2. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity. The VSL for TOP-004 R1 states, "The Transmission Operator did not operate within an identified Interconnection Reliability Operating Limits (IROL) and the associated IROL Tv for any single occasion." This should be changed to state, "The Transmission Operator failed to mitigate an identified Interconnection Reliability Operating Limits (IROL) and within the allotted IROL Tv for any single occasion." The VSL for TOP-004 R2 as written implies that an entity with only 1 tie line would not receive a violation greater than "lower." In addition, as written these VSLs seem to allow the Compliance Auditor the opportunity to choose how to apply the VSL. As an example the entity with one tie line could be found to be guilty of a "Lower" violation because they missed their one directly connected entity or they could be guilty of a "Severe" violation because they missed 100% of their directly connected entities. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity.
Yes
Yes
While we support the reduction in the overall number of standards, the deleted standards contained some requirements whose deletion we can not support. We have communicated these requirements and the issues surrounding them in the responses to other questions on this form including question 12 at the end of this form.
Not aware of any.
Yes
In TOP-001-2 R2, the term "disconnections" is ambiguous. In addition, as written this requires the RC be notified prior to operator action. While we agree that we do not want operators taking actions that sacrifice accuracy for speed, we do not support the concept of approving all mitigation actions prior to implementation. Nor do we believe this concept serves to preserve or enhance reliability in situations where time is of the essence. The motivations behind the original requirements were 1) to preserve the reliability of the interconnection through recognition and mitigation actions and 2) to ensure that removal of overloaded transmission facilities was done only when it preserved or enhanced reliability. We feel these two concepts should be managed as individual requirements similar to the requirements in effect today. The Drafting Team should include the system conditions of overload, abnormal voltage, and reactive conditions, and endangered equipment as system conditions permissible for action then communication. In TOP-001-2 R3, the Drafting Team dropped the concept of the requesting entity implementing its comparable emergency procedures prior to an entity being required to lend assistance. This could lead to a request and requirement for TOp A to shed load in its area when TOp B, the entity requesting the assistance, has not shed load that would mitigate the emergency in its own area. This requirement should be revised to state, "Each Transmission Operator, Balancing Authority, and Generator Operator shall render emergency assistance to others, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements and provided the requesting entity has implemented its comparable emergency procedures." In TOP-001-2 R4, the Drafting Team preserved limiting the delay in notifications to system conditions. This change as written does not provide additional clarity as to which system conditions require and do not require notification in advance of action. This seems to make this Requirement too vague to be measurable. As currently proposed, this requirement means someone must decide which system conditions require and do not require advance coordination. Additional rules need to be developed by the team concerning the system conditions that require notification in advance of action. While we agree that we do not want operators taking actions that sacrifice

accurracy for speed, we do not support the concept of approving all mitigation actions prior to implementation. Nor do we believe such a concept serves to preserve or enhance reliability in situations where time is of the essence. We recommend the drafting team restore TOP-001-1 R7.3 that states, "When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, GOp notifies TOp, TOp notifies RC and adjacent TOps at earliest possible time." As currently written this proposed requirement leaves it open for the operator to complete the mitigation actions prior to notifications taking place when system conditions do not permit such coordination which is inconsistent with the Drafting Team's action on other requirements, but is appropriate considering the potential system conditions. In TOP-001-2 R5, the Drafting Team is supporting action in advance of communication, we support this stance. The Drafting Team proposes to delete TOP-007-0 R3 that states, "A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2" because the authority already exists and does not need to be cited in a requirement. Other than the Reliability Standards, where does this authority exist? It seems that the drafting team intends to remove all requirements that provide for this authority in the Reliability Standards. We cannot support this stance. Without this provision in the standards, there is nothing to preclude an organization from requiring its operators to obtain approval from superiors within the organization prior to taking an action such as load shed, redispatch, reconfiguration, etc. that they know will preserve or enhance the reliability of the BES. While we agree these requirements do not provide any legal protection to the operator, they do enhance reliability of the BES by ensuring authority to act remains in the hands of the operator at the controls of the System. The Drafting Team deleted TOP-002-2 R1 because they feel the BA only needs to respond to CPS and DCS. Does the BA only have responsibility for responding to CPS and DCS? How does the TOp meet its obligations without BA assistance? How about MVAR support? It is not realistic to require a TOp to issue a reliability directive to a BA, GOp, GO, DP, etc. each time it needs some assistance in preparing a plan for future system conditions. We request the Drafting Team reconsider the application of the "BA only needs to respond to CPS and DCS" concept and instead apply the measure of reliability of the BES as the litmus test for requirements. The Drafting Team deleted TOP-002-2 R2 as a good utility practice that is not measurable. We support this change since the TPL standards will support the interface between operations and planning. The Drafting Team deleted TOP-002-2 R3 as the LSE and GOP are governed by their Interconnection Operating Agreements. We are concerned with relying on agreements as a sole means of providing for BES Reliability. Reliability related behavior is best governed by reliability standards. Therefore, we request the drafting team reinstate R3 of TOP-002-2. In TOP-002-3 R1 and R2 the drafting team dropped the BA plan from the requirement. How will the TOP obtain information and assistance needed from the BA necessary to plan to meet scheduled system configuration in light of the fact that the work plan for these standards does not include any revisions to the BAL standards to require that support? The Drafting Team deleted TOP-002-2 R7. With this deletion, how will the BA's plan for energy reserves insure its deliverability without TOp assistance? The implementation plan does not include any revisions to the BAL standards to verify deliverability. This deletion seems to segment the planning activities too much to ensure reliability. The Drafting Team deleted TOP-002-2 R8 and R10. With this deletion, how does the TOp meet its voltage and reactive obligations without BA assistance? The implementation plan does not include any revisions to the BAL standards and CPS and DCS do not cover reactive support. Whatâ€™s left in the standards to ensure reactive capacity is available on generating units to support voltage needs? The Drafting Team deleted TOP-002-2 R18. This requirement should be retained and revised to state, "Neighboring BAs, TOps, TOs, use identical Tie- line names based on terminal end facility names when referring to transmission facilities.â€ The purpose of this requirement is to ensure Company A and Company B are sure they are talking about the same Tie-line. The Drafting Team deleted TOP-003-0 R1. This deletion eliminates the requirement for the GOp to provide outage data to the TOp. This requirement should be retained. The Drafting Team has developed this standard based on the changes planned or proposed for other standards. This standard should not be finalized until all other standards that these changes are based on have been regulatory approved in order to avoid creating a reliability gap through deletion of an existing standard and the failed adoption of a proposed standard. TOP-004-3 R2 uses the term "Agreement" that is currently defined as "A contract or arrangement, either written or verbal and sometimes enforceable by law." Until the proposed revision to the definition of the term "Agreement" that would include "mutually agreed upon procedures and protocols" this requirement should be revised to state, "TOp has Agreements or mutually agreed upon procedures or protocols with directly interconnected TOps that specify switching of synchronous BES tie lines." TOP-003-1 R1 be revised to state, "Each Transmission Operator, Balancing Authority, Generator Operator, Generator Owner, Transmission Owner, Purchasing-Selling Entity, Load Serving Entity, and Distribution Provider shall provide all data requested in writing by the Transmission Operator or Balancing Authority using the periodicity and in the format requested." With the adoption of this change, TOP-003-1 R2, R3, and R5 could be dropped because R1 covers all entities and data requirements. In addition, with this change, the VRF for R1 should be changed to "High." The PSE should be added to the applicability of this requirement as they may

have information that intermediary TOps need concerning large magnitude near-term sales and purchase power transfers that are unconfirmed with a high probability of implementation that should be studied by operations planners for potential impacts on the reliability of the BES. The Drafting Team proposes to delete the TOP-006-1 R5, R6 and R7 as they are "covered by the certification process and no longer necessary." The certification program is being scaled back in part due to the reliability standards and the drafting team is removing requirements from the standards because the certification program covers it. We should not rely on programs outside of the reliability standards to provide for the reliability of the BES. These three requirements should be reinstated and revised to improve clarity and measurability.
Group
MRO NERC Standards Review Subcommittee
Jim Haigh
WAPA
Yes
Yes
Yes
Yes
No
This question is not consistent with TOP-004-2 M1, you either need the report or the data. You should be able to prove compliance with the report, stating absence of an IROL Violation Report in the question does not make sense.
Yes
No
1. The measures seem to repeat the requirements perhaps this could be avoided since additional detail in the measures are not enforceable only the requirements are. 2. In the standard TOP-001-2 the retention period for requirement 5 and measure 5 is longer than required for R1 through R4, what is the reasoning for this? 3. In the standard TOP-001-2, there is no retention period given for requirement 6 and measure 6. 4. In all of the standards and in the last sentence of the section "1.4 Data Retention", isn't it extreme to retain "all" requested and submitted subsequent audit records? 5. In the standard TOP-002-3, requirement 3 depends on requirement 2 but these requirements don't have the same retention period, should they? 6. Measure 5 of the standard TOP-003-1 references requirement 9, shouldn't it reference requirement 5? 7. In the standard TOP-003-1, the retention periods for R4/M4 and R5/M5 are only for 90 calendar days but the rest of the requirements have a retention period for 3 years, shouldn't R4/M4 and R5/M5 have the same retention period as the rest of the requirements in this standard? 8. The MRO has concerns about storing large amounts of real-time data. In TOP-003-01, should R1, R4, and R5 data retention be set at 90 days? 9. In the standard TOP-004-3, M2's last sentence references the text "confirmation". What is needed for confirmation? Would a signature page be an example?
No
1. For the TOP-001-2 VSLs for R1, these VSLs should be reworded because complying to the requirement would meet those VSLs. The MRO would suggest replacing "unless" with an "and" plus change the trailing text to read "â€¦ the respective entity did not inform the transmission operator â€¦". 2. For the TOP-001-2 VSLs for R2, what about the situation where the transmission operator did inform the RC and the affected TOP of a real-time emergency condition on an occasion but the notification was after the disconnection of switches? 3. For the TOP-001-2 VSLs for R4, what if the TOP or GOP does not coordinate because of system conditions. Is it possible that those entities might disagree as to what is a system condition? How would this disagreement be handled? 4. For the TOP-001-2 VSLs for R6, the timing is only one element of the evidence. These VSLs should be rewritten because the VSLs add to the requirement. The VSL should be changed to replace "the timing of when it acted" with "its actions" plus, add the text "when it" between the words "or" and "directed others".
Yes
Yes
Yes

Yes
In standard TOP-004-3 and in section "1.5 Additional Compliance Information", what if you don't meet this reporting process? What will happen?
Individual
Rick White
Northeast Utilities
Yes
Yes
No
We do not believe that the TOP informing the RC of every SOL exceedance should be required, and would not facilitate preserving reliability. Suggest removing "or SOL" from the requirement.
No
Suggest adding the words "such as P/SSE, power flow, etc." to the definition after the word "models". This might help to clarify the intent. Ending the definition after the word "responses" would make it a cleaner definition. Additionally, the defined term is "Simulated Contingencies". R1 uses the term "Simulated Contingency". This should be reconciled by either changing the defined term, or R1 should use the defined term and drop the word "events" from the end of the sentence.
Yes
We agree that having evidence of non-events has little value.
No
TOP-002 - Raise R1 from Low to Medium.
Yes
Yes
Yes
Yes
No
No
Group
ITCTransmission
Michael Ayotte
ITCTransmission
Yes
Yes
No
Presumably the RC should be aware when an SOL has been exceeded by their own EMS and contingency analysis program.
No
Suggest using the phrase "potential contigency" rather than "simulated contingency".
Yes
Yes
No
In TOP-001, the majority of retention requirements are current year plus one, except one is 3 years and one isn't specified. All retention requirements in this standard should be the same. In TOP-002 M1 add operating plans or guides as evidence that an assessment was performed. In TOP-002 retention requirements should be the same for all requirements.
No

TOP-001 R1 Failure to follow a directive one even one occasion without reason should be treated as a severe VSL, similar to R3. TOP-002 R1 & R2 VSL should not be severe, there should be VSLs at all levels. It is not logical to have a severe VSL for not performing a day ahead analysis, and a Lower VSL for not following a reliability directive. TOP-004 R4 should have VSL for all levels, similar to R2,R3
Yes
Yes
No
Yes
TOP-001 R2 the phrase "disconnections prior to switching" needs to be clarified. Does this refer to individual facilities or complete disconnection from an interconnection? TOP-001 R3 It would be helpful to have a definition of 'emergency', recognizing this is a broader issue than just this standard. TOP-003 R1 It is unclear who is this data exchange requirement is applicable to. By reading on to R2 and R3, one can assume the intended audience, however the requirement should be written to clear as a standalone item. TOP-004 R1 This requirement should be incorporated into TOP-001, as it logically flows from the requirements there. This would facilitate possible eliminate of TOP-004 altogether. TOP-004 R2 The phrase "specify switching" is unclear. Believe this is an unnecessary requirement as TOP-001 R4 already requires the coordination of operations.
Group
IRC Standards Review Committee
Charles Yeung
Southwest Power Pool
Yes
We agree with the change. The drafting team could address the timeliness of actions in the VSLs. If directed by the FERC to maintain the language, we suggest the wording to be "as soon as possible but within the time limitation of the associated SOL".
Yes
SOLs should be mitigated within their equipment time limits. Though we are not prepared to propose a specific time period due to the limited time to provide comments on such a complex issue, we ask that the SDT work with industry to develop an appropriate time period that is measurable and propose it for consideration. The procedures should give appropriate consideration to consequences that are more severe than the violation.
No
We suggest using the term "potential contingencies" and avoid coming up with a new definition. The proposed definition is unclear and will lead to confusion.
Yes
We agree that having evidence of proof for non-events does not make sense. These are event-triggered standards and the focus should be to have evidence of compliance when an event in which compliance was required occurred. Some would argue that evidence is needed because a TOP could fail to report an event. It should be kept in mind that a TOP that fails to report a violation would also be able to manipulate data to show continuous compliance.
No
TOP-001 R1: A High VRF may not be appropriate in all cases. There are some directives that relate to local limits that would by no means result in cascading outages or instability. Perhaps the VSL matrix should assign a low VSL for non IROL directives. R2: We are unable to assess the VRF for this requirement since we do not understand the meaning of "â€¦.potential impacts caused by disconnections prior to switching." R3: We do not necessarily agree with a High VRF for the same reason as for R1, unless the VSL matrix addresses the difference between extreme events and local issues. TOP-002 R1: We suggest raising the VRF for R1 to a Medium. TOP-003 R5: Should perhaps be elevated to Medium if the measure were more specific. An entity can't prove the negative (prove you've provided data to every entity that requested it). The measure and VSL should deal with a complaint being submitted by an operating entity that did not get the data it needed and requested.
No
In general, TOP-001 is an event triggered standard. For example, a limit is violated and not corrected, an entity failed to followed a directive, etc.. Since it's impossible to prove the negative when there isn't an event, what these measures will cause is entities to pass requests around to get statements from others to have something to show an auditor. TOP-003 It should be acceptable (rather that keeping evidence that each entity was sent a specification) that the

specification be available to an accessible site and that the entities were made aware of its location. The measures should revolve around failure to obtain or provide data and either an event occurred or a complaint arose.
No
In general, these are binary requirements. An entity followed a directive or not, data was provided or it was not, a study was done or it was not. The true fix is to develop a sanctions matrix that deals with binary requirements rather than coming up with subjective ways to measure something that is yes/no. That said, we would not recommend spending a great deal of time making modifications, as there will most likely be an order directing modifications once the standard is filed.
Yes
Yes
No
Yes
We appreciate this as a first effort in reducing the redundancy in the V0 standards. There should be some clarity in the use of the term SOL in these standards. According to the NERC Glossary, SOLs include both IROLs and local facility limits. These standards use SOL in the context of only a local facility limit. The temporary exceedance of local facility limit (within the time limitations of the rating) should not be construed to be a violation in these standards. Failure to correct a local facility limit to the point where it leads to an IROL or damages equipment should be a violation. Records should only be maintained if the local limit is exceeded and not corrected within the allowable time of the limit. The record keeping required for non-violations in these standards is unnecessary.
Individual
Jason Shaver
American Transmission Company
Yes
Yes
Yes
No
The phrase "Simulated Contingency" should be replaced with a more concrete concept. ATC suggest that the SDT link the requirement to FAC-011. The purpose of FAC-011 is to ensure that SOLs used in the reliability operations of the BES are determined based on an established SOL methodology.
Yes
Yes
Yes
No
TOP-001-2 VSL: VSLs for R1 and R2 are written for when an entity does not follow a directive multiple times. Per FERC VSL should be based on the single non-compliance event. ATC suggest that the VSLs be re-written based on FERC guidelines. VSLs for R5 and R6 are based on the entity not having evidence of compliance not on the fact that they did not comply with the requirement. ATC suggest that the VSL be rewritten in order to address the requirement not the evidence to support the requirement. VSL for TOP-002-3 Requirement 3: If in a plan you identify one reliability entity and fail to notify that entity what is the VSL level that will be assigned. This seems to fall in both Lower and Severe. ATC believes that the VSL's should only have a single method for determining the VSL level in order to prevent conflicting determinations.
Yes
Yes
No

Yes
TOP-001-2 Requirement 2: First Concern: NERC Definition for Emergency: "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System" ATC's believe that anticipating an abnormal system condition that could result in an Emergency would be very difficult to certify compliance. It's our position that the requirement should be limited to actual Real-Time Emergency conditions. If the SDT disagrees than we request information on how a company could certify compliance on its ability to anticipate an emergency. Second Concern: Currently the requirement requires notification of an automatic or immediate manual action prior to the action for an Emergency. We believe that notification prior to switching may put the system and/or equipment at a greater level of risk. The requirement should contain language that states notification should be done "if time permits" otherwise it should be done following the action. TOP-001-2 Requirement 4: What is the minimum level of "affect" that requires communication? TOP-002-3 Requirement 1: Would a single assessment of next day's operation satisfy this requirement? or, Is the requirement asking for multiple next day operations to account for load changes expected throughout the day?

Consideration of Comments on First Draft of Revised TOP Standards Real-time Operations — Project 2007-03

The Standards Committee thanks all commenters who submitted comments on the 1st draft of the revised TOP standards, Real-time Operations Project. These standards were posted for a 45-day public comment period from October 7, 2008 through November 20, 2008. The stakeholders were asked to provide feedback on the SAR through a special Standard Comment Form. There were more than 26 sets of comments, including comments from more than 90 different people from approximately 50 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

The SDT is recommending that the standards be re-posted to allow for feedback on the changes made due to industry comments to the first posting.

Changes have been made to the following:

- TOP-001-2 & TOP-003-1 Purpose statements
- Requirements:
  - TOP-001-2: R1, R2, R3, R4, and R7
  - TOP-002-3: R1, R2, and R3
  - TOP-003-1: R1, R4, and R5
  - TOP-004-3, R2
- Measures:
  - TOP-001-2, M1, M2, M3, M4, and M7
  - TOP-003-1, M1, and M4
  - TOP-004-3, M2
- Data retention:
  - TOP-001-2, R1 through R7
  - TOP-002-3, R3
  - Top-003-1, R1, R4, and R5
- VSLs:
  - TOP-001-2, R1, R3, R4, and R6
  - TOP-002-3, R1 and R3
  - TOP-003-1, R1, R2, R3, and R4
  - TOP-004-3, R1 and R2
- In addition, two bullets were added to TOP-003-1, Requirement R1.1 to address directives in FERC Order 693.

Definitions:

- Deleted the definition of "Simulated Contingencies" as stakeholders indicated the definition is not needed.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 – Regional Reliability Organizations, Regional Entities

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	Guy Zito	NPCC										✓

	Additional Member	Additional Organization	Region	
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
3.	Mike Gildea	Constellation Energy		6
4.	Greg Campoli	New York Independent System Operator	NPCC	2
5.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
6.	Chris De Graffenried	Consolidated Edison Company of New York, Inc.	NPCC	1
7.	Don Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
8.	Brian Evans-Mongeon	Utility Services, LLC	NPCC	6
9.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Lee Pedowicz	NPCC	NPCC	10
12.	Kathleen Goodman	ISO - New England	NPCC	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Terry L. Blackwell	Santee Cooper	✓									

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Glenn Stephens	Santee Cooper	SERC	1
3.	Jim Peterson	Santee Cooper	SERC	1
4.	Vicky Budreau	Santee Cooper	SERC	1
5.	Kristi Boland	Santee Cooper	SERC	1
6.	Rene' Free	Santee Cooper	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Jim Griffith	SERC OC Standards Review Group	✓		✓		✓					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Brown	Big Rivers Electric Cooperative	SERC	1, 3, 5
2.	Robert Thomasson	Big Rivers Electric Cooperative	SERC	1, 3, 5
3.	Raleigh Nobles	Georgia System Operations Corp.	SERC	3
4.	Sam Holeman	Duke Energy Carolinas	SERC	1, 3, 5
5.	Greg Rowland	Duke Energy Carolinas	SERC	1, 3, 5
6.	Dan Jewell	Louisiana Generating, LLC	SERC	1, 3, 5
7.	Jason Marshall	MISO	SERC	2
8.	Larry Rodriquez	Entegra Power Group;	SERC	5
9.	Melinda Montgomery	Entergy	SERC	1, 3, 5
10.	Jim Case	Entergy	SERC	1, 3, 5
11.	John Troha	SERC	SERC	10

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Patrick Brown	PJM Interconnection		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al DiCaprio	PJM interconnection	RFC	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Louis Slade	Dominion - Electric Market Policy			✓		✓	✓				

	Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jalal Babik		NA - Not Applicable	3, 5, 6
2.	Mike Garton		NA - Not Applicable	3, 5, 6

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Roman Carter	Southern Company Transmission	✓									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chris Wilson	Southern Transmission	SERC	1
2.	Terry Coggins	Southern Transmission	SERC	1
3.	JT Wood	Southern Transmission	SERC	1
4.	Jim Busbin	Southern Transmission	SERC	1
5.	Mike Oatts	Southern Transmission	SERC	1
6.	Jim Viikansalo	Southern Transmission	SERC	1
7.	Dushaune Carter	Southern Transmission	SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Denise Koehn	Bonneville Power Administration	✓		✓			✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Snodgrass	Transmission Dispatch	WECC	1
2.	Jim Burns	Transmission Technical Operations	WECC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Jason Marshall	Midwest ISO Stakholders Standards Collaborators		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Cyrulewski	JDRJC Associates	RFC	8

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Dave Folk	FirstEnergy	✓		✓		✓	✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FirstEnergy	RFC	1, 3, 5, 6
2.	Sam Ciccone	FirstEnergy	RFC	1, 3, 5, 6
3.	John Martinez	FirstEnergy	RFC	1
4.	Steve Megay	FirstEnergy	RFC	1

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
10.	Jim Haigh	MRO NERC Standards Review Subcommittee	✓					✓				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Charles Lawrence	ATC	MRO	1
5.	Ken Goldsmith	ALTW	MRO	4
6.	Terry Harbour	MEC	MRO	1, 3, 5, 6
7.	Pam Sordet	XCEL	MRO	1, 3, 5, 6
8.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
9.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
10.	Joseph Knight	GRE	MRO	1, 3, 5, 6
11.	Joe Depoorter	MGE	MRO	3, 4, 5, 6
12.	Larry Brusseau	MRO	MRO	10
13.	Michael Brytowski	MRO	MRO	10

Commenter		Organization	1	2	3	4	5	6	7	8	9	10
11.	Michael Ayotte	ITC Transmission	✓									
12.	Charles Yeung	IRC Standards Review Committee		✓								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Patrick Brown	PJM	NPCC	2
2.	Jim Castle	NYISO	NPCC	2
3.	Matt Goldberg	ISONE	NPCC	2
4.	Lourdes Estrada-Salinero	CAISO	WECC	2
5.	Anita Lee	AESO	WECC	2
6.	Steve Myers	ERCOT	ERCOT	2
7.	Bill Phillips	MISO	RFC	2
8.	Dan Rochester	IESO	NPCC	2

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
13.	Cleyton Tewksbury	Montenay Power Corp.					✓					
14.	John McCawley	PECO Energy	✓		✓							
15.	Craig McLean	Manitoba Hydro	✓		✓		✓	✓				
16.	Scott Berry	Indiana Municipal Power Agency				✓						
17.	Jianmei Chai	Consumers Energy Company			✓	✓	✓					
18.	Kirit Shah	Ameren	✓		✓		✓	✓				
19.	Darryl Curtis	Oncor Electric Delivery	✓									
20.	Will Franklin	Entergy System Planning & Operations (Gen & Mktg)						✓				
21.	Edward J Davis	Entergy Services	✓		✓		✓	✓				
22.	Dan Rochester	Independent Electricity System Operator		✓								
23.	Greg Rowland	Duke Energy	✓		✓		✓	✓				
24.	Thad Ness	AEP	✓		✓		✓	✓				
25.	Rick White	Northeast Utilities	✓									
26.	Jason Shaver	American Transmission Company	✓									

1. The SDT has deleted the phrase 'without intentional delay' from all situations that require specific actions or responses as it was felt that this term is unmeasurable and that operator action and response in a timely manner is part of good utility practice and common sense. Do you agree with this change? If not, please provide specific suggestions for improvement.

Summary Consideration:

The majority of respondents agreed with the deletion of the phrase 'without intentional delay' and thus no changes have been made to the standard.

Organization	Yes or No	Question 1 Comment
ISO-NE NPCC	No	Although we agree with the concept and agree that it is unmeasurable, we do not believe that removal of the concept is acceptable and suggest reqording to "as soon as possible but not more than..."
ISO-NE	Yes	We agree with the change. The drafting team could address the timeliness of actions in the VSLs. If directed by the FERC to maintain the language, we suggest the wording to be "as soon as possible but within the time limitation of the associated SOL".
Response: The use of the term "without intentional delay" was used in context with how quickly the responsible entity acts and not how quickly its actions achieved the desired response. Your suggestion appears to attempt to time bound the amount of time it takes to achieve results from the actions taken by the responsible entity. Thus, the SDT does not agree with your suggestion. Additionally, the definition of SOL does not include a time limit.		
IRC Standards ISO-NE NPCC Review Committee	Yes	We agree with the change. The drafting team could address the timeliness of actions in the VSLs. If directed by the FERC to maintain the language, we suggest the wording to be "as soon as possible but within the time limitation of the associated SOL".
Response: The SDT does not believe that timeliness should be addressed in the VSLs unless there is a clear measurable requirement for timeliness. The Commission established in their VSL order several guidelines, one of which requires that VSLs do not add to the requirement. Establishing timeliness in the VSLs when there is not a clear measurable requirement for timeliness would thus violate the Commission's guideline.		
Entergy Services	No	There is merit in holding entities accountable for making timely notifications, etc. Would an entity be compliant if they waited 6 months to notify the TOP of changed in Real Power capability? Perhaps the measures can be worded such that proof of the event's time and proof of the notification's time are not significantly different. However, we suspect that entities for which the requirement is applicable would WANT guidance on what is timely and what is not. Leaving that much up to the interpretation of audit teams is not very desirable.

Organization	Yes or No	Question 1 Comment
Response: While the SDT agrees with your point that entities would want guidance on what is timely and agree that the extreme example of six months would be far too long, the SDT noticed that you have not suggested a time requirement. Thus, the SDT concludes that you must have detected the problems with establishing a time requirement. Some of the problems include that what is timely in one situation and one applicable entity may ultimately vary with another. Thus, setting a specific time requirement that is measurable and usable in all situations is not appropriate. The SDT also agrees that it is not desirable to leave the interpretation of what is timely up to the compliance auditors but do not see a better way. Applicable entities will have to work with their TOP to assess what their expectations are as far as timeliness.		
Independent Electricity System Operator	No	This phrase should not be removed. If measurability is required, similar language ("without delay") in R4 of the recently approved IRO-009 standard should be used, with a condition to assess if there was a 5 minute delay for assigning a High VSL.
Response: This is the only comment that was received in this regard and the SDT (and the remainder of the industry as seen from comments received) continues to believe that removing the phrase is correct for TOP standards.		
Santee Cooper	Yes	
SERC OC Standards Review Group	Yes	This phrase is not measureable!
PJM InterconnectiC OC Standaon	Yes	PJM supports the deletion and recognizes the problem in measuring "intent".
Dominion - Electric Market Policy	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	
Midwest ISO Stakholders Standards Collaborators	Yes	Intent is an enforcement issue. Thus, it does not belong in the standard.

Organization	Yes or No	Question 1 Comment
FirstEnergy	Yes	
MRO NERC Standards Review Subcommittee	Yes	
ITC Transmission	Yes	
Montenay Power Corp.	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	
Oncor Electric Delivery	Yes	
Entergy System Planning & Operations (Gen & Mktg)	Yes	
Duke Energy	Yes	
AEP	Yes	
Northeast Utilities	Yes	
American Transmission Company	Yes	
Response: Thank you for your response.		

2. The SDT has eliminated SOLs from TOP-004-2, Requirement R1. The SDT felt that requiring a TOP to operate within all SOLs could effectively reduce the TOPs operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time. The SDT determined that operating within each IROL and its IROL T_v was the reliability issue in this requirement. Do you agree with deleting the language about SOLs in TOP-004-2, Requirement R1? If not, please provide specific suggestions for improvement.

Summary Consideration:

There was a general consensus amongst responders that the elimination was appropriate.

Organization	Yes or No	Question 2 Comment
SERC OC Standards Review Group	Yes	Although we agree with the SDT's change regarding SOLs, TOPs should not allow an unintended consequence of this change to be less emphasis on resolving or mitigating SOLs.
Response: The SDT agrees with you that the TOPs should not de-emphasize resolving or mitigating SOLs and do not believe the revised standard does this.		
Midwest ISO Stakholders Standards Collaborators	No	The TOP should be required to operate within SOLs. SOLs by definition can by be voltage or stability limited. SOLs, if exceeded, can be become IROLs. What in the standards will ensure that the TOP is sure the exceeding the SOL will not result in an IROL. The situation described in the question may not even require that an SOL be defined. No where in the standards is there a requirement that every thermal limit must be encompassed in a SOL. If a TOP decides to "ride" out an SOL rather than mitigate the violation, in reality the TOP has indicated that the current SOL is invalid. Why can't the TOP just determine what the new SOL is?
Response: IROLs must be determined by studies. To the extent that a TOP has an expectation that an SOL might be exceeded, the TOP and RC are obligated to verify that an IROL will not be exceeded. In other words, when determining the operating region, the TOP and RC must be aware of both the SOL operating region and the IROL operating region. Honoring every SOL could present problems to the TOP where they may have to choose to violate another requirement to meet the requirement to operate within all SOLs. For example, when two or more limits are in danger of violation, and mitigating one would exacerbate the other, the TOP clearly is faced with a reliability and compliance conundrum. Under the SDT's proposal, however, the TOP has the opportunity to monitor the status of the systems and make the wisest possible choice to preserve reliability. The SDT feels that the FAC standards address thermal limits.		
Independent Electricity System Operator	No	We strongly disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time."

Organization	Yes or No	Question 2 Comment
		SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability? Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? We are also very concerned that R1/R2 in TOP-002 requires the TOP to assess potential exceedence of IROLs only but not SOLs. This sends a the wrong message to the industry that TOPs do not need to plan their operations to within established SOLs. So why do we mandate the TOPs to calculate SOLs to begin with? We feel strongly that R2 in TOP-002 should be revised so that it includes as part of the requirement, preclusion of operating in excess of any SOLs. We believe that completely removing SOLs from the requirement is contrary to the long-term objective of enhancing reliability. Further, we believe that all SOLs should be respected in the planning time-frame and in real time with the exception of low likelihood or rare circumstances. We do recognize that there are instances where post-contingency, a TOP may not be able to respect its repreparation limits for the next contingency. Those instances must however be limited to situations in which, after applying available means to eliminate the violation short of firm load shedding, and where it can be demonstrated that the SOL violation cannot propagate into an IROL violation following the next worst contingency. That is, the repreparation limit is non-impactive to the BES. We need only recall that some blackout events started by exceedence of local area limits (SOLs). When sufficient events occur (such as when a line rating is not observed or its overload not corrected), cascade overloading on another transmission line and yet another transmission line and so on may occur. An apparently non-impactive SOL, if not observed and whose exceedence not corrected, can result in cascading outages.
Response: Your initial argument that exceeding an SOL may be the point where “system voltage may be depressed” focus on the subset of SOLs that are IROLs. There is an explicit requirement still in the proposed standards to operate within IROLs. Thus, the only SOLs that these proposed draft standards do require a TOP to operate within are those that exclude the IROL subset. The SDT does not believe that the proposed TOP standards conflict with the FAC-014 standard. Determining SOLs is required to operate the System and SOLs will be operated within in most instances. However, SOLs do not represent limits that if exceeded could cause cascading, uncontrolled outages or blackouts. Furthermore, part of the purpose of FAC-014 is to communicate your SOLs to other entities so that they can respect your operational limits.		
IRC Standards Review Committee	Yes	SOLs should be mitigated within their equipment time limits. Though we are not prepared to propose a specific time period due to the limited time to provide comments on such a complex issue, we ask that the SDT work with industry to develop an appropriate time period that is measurable and propose it for consideration. The procedures should

Organization	Yes or No	Question 2 Comment
		give appropriate consideration to consequences that are more severe than the violation.
Response: SOLs may be based on equipment time limits but by definition there is not an associated T_v and any decision to associate a time limit with the SOL to protect the equipment from damage is an independent operational decision that is made by the TOP and TO. Thus, the SDT does not believe it is necessary to establish a time limit.		
AEP	Yes	The purpose statement in TOP-004-1 is consistent with the IROL NERC defined term. We suggest keeping the original purpose statement from TOP-004-1. If SOL are to be reported then some prioritization needs to be given. We suggest reporting the largest SOL if there are several common to an area of congestion.
Response: Purpose statement **–** No other comments were received and the SDT feels that the changes properly reflect what was changed in the standard so no changes made**.** Prioritization or largest SOL – Most commenters support the removal of SOLs. Therefore, no change is required.		
ISO-NE	Yes	SOLs should be mitigated within a defined time period with appropriate consideration to the consequences
NPCC	Yes	
Santee Cooper	Yes	
PJM Interconnection	Yes	The SDT has correctly balanced the need for flexible responses to non-impactive problems.
Dominion - Electric Market Policy	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Subcommittee	Yes	
ITC Transmission	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	This change is consistent with the fact that BES operation is a risk-based endeavor. While IROL risk is so severe it is unlikely to be properly evaluated by a TOP, SOLs should be considered as part of the normal risk assessment.
Oncor Electric Delivery	Yes	
Entergy Services	Yes	We agree as this was the original intention of the NERC OLDTF that first developed the terms SOL and IROL.
Duke Energy	Yes	We agree with the SDT's logic in eliminating SOLs from TOP-004-2 Requirement R1.
Northeast Utilities	Yes	
American Transmission Company	Yes	
Response: Thank you for your response.		

3. The SDT is concerned about the inclusion of SOL in TOP-001-2, Requirement R5. The SDT thinks that the TOP notifying its RC of every SOL that has been exceeded may create an overload of messages for the RC that does not facilitate preserving reliability. Do you agree that SOL should remain in this requirement? If not, please provide specific suggestions for improvement.

Summary Consideration:

This question was poorly worded and as a result the commenters may have been led astray. The consensus of the industry at this point is that not all SOLs need to be reported but that some subset of them should. The SDT will re-phrase the question in the second posting so that the intent is clear and so that a definitive position on the issue can be established.

Organization	Yes or No	Question 3 Comment
NPCC	No	We agree that not every SOL requires communications to another entity. However, there are subsets of SOLs that have the potential to become IROLs or, outside of that subset, left unmitigated, there are other SOLs which will become IROLs. We believe that there should be a requirement to inform the RC when these conditions occur.
ISO-NE	No	We agree that not every SOL requires communications to another entity. However, there are subsets of SOLs that have the potential to become IROLs or, outside of that subset, left unmitigated, there are other SOLs which will become IROLs. We believe that there should be a requirement to inform the RC when these conditions occur.
Santee Cooper	No	Notification should be provided to the RC only when an IROL is exceeded. Too much information flowing to the RC could potentially mask a reliability problem.
SERC OC Standards Review Group	Yes	We interpret this requirement to indicate that a TOP is required to inform the RC only if action is taken to mitigate an SOL, i.e., if the TOP decides that no action is required for an SOL, the TOP is not required to notify the RC.
Manitoba Hydro	No	As per TOP-004-3, exceeding an SOL does not necessarily put the BES at risk. The SOL for a thermal limit could very well be set for an ambient temperature much higher than the actual ambient temperature. Notifying the RC for such an event would be a waste of resources. We feel it is not necessary to make it mandatory to notify the RC when exceeding a SOL. TOPs should be mandated by a Requirement to document all SOL violations and action taken. Such action may include but is not limited to: simply further monitoring or making a temporary alarm level adjustment.
PJM Interconnection	No	The issue here is in defining what is impactive and what is not. A flow value that creates a temporary overload on a radial line may not be of concern to an RC, thus informing the RC that the flows are under the limit is merely a distraction. During Emergency Conditions such non-relevant information can be more then distractive it can needlessly tie up people

Organization	Yes or No	Question 3 Comment
		to the point of causing those people to overlook real problems. The standard could be written to include a requirement that the RC must inform the TOP of any overloads that it, the RC, requires to be informed of. Then the TOP is obligated to provide information about the critical SOLs and mandated to report on the relief of every SOL.
Dominion - Electric Market Policy	Yes	Suggest revising R5 to read "Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when a reportable SOL (as identified by its Reliability Coordinator)has been exceeded. Suggest revising R6 to read "The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv and shall inform its Reliability Coordinator of such actions.
Southern Company Transmission	No	Requirement 2 of TOP-001-2 already contains a provision for the TOP to inform its RC of real-time or anticipated emergency conditions. If a particular SOL is considered an emergency condition, then it would be reported. Otherwise, it is not required. Therefore, we agree that notifying the RC of every SOL is not necessary.
Ameren	No	This has proven to be a duplicative effort since the RC is monitoring the facilities also. Change the text to say, "to the extent that the RC does not have systems in place, the TOP will ?.".
Midwest ISO Stakholders Standards Collaborators	Yes	We believe that the TOP notifying the RC of every SOL that has been violated does not create an overload messages. The TOPs in the Midwest ISO reliability footprint already notify the RC of all SOL violations and we have not found it to be a burden. In fact, we have found it actually improves operations because it causes the RC to continuously validate the results of the real-time contingency analysis against the TOPs. We do believe that the requirement should not be prescriptive to require a particular type of communication such as via the phone. To a certain degree this requirement can be met by simply having redundant models and contingency analysis in the EMS. We observe that the requirement is not for the TOP to notify the RC every time that an SOL is violated. In fact, the requirement is only to notify the RC of the actions to be taken. Thus, if no actions are taken, the TOP does not have to notify the RC. We believe the language should be strengthened to clarify that the TOP should notify the RC every time an SOL is violated even when no mitigation is taken.
FirstEnergy	No	However, the SDT should develop rules that will drive the reporting of incidences where entities exceed SOLs on a regular basis. As an example: the operating studies show that the facility emergency thermal limit is expected to be exceeded by 25% for 4 consecutive hours of 5 consecutive operating days. The goal should be to flag instances where SOLs are exceeded on a regular or routine basis in an effort to highlight situations where mitigation actions or system reinforcement projects may be needed or required to preserve the reliability of the BES.
ITC Transmission	No	Presumably the RC should be aware when an SOL has been exceeded by their own EMS and contingency analysis program.

Organization	Yes or No	Question 3 Comment
Montenay Power Corp.	No	
Ameren	No	This has proven to be a duplicative effort since the RC is monitoring the facilities also. Change the text to say, "to the extent that the RC does not have systems in place, the TOP will ?.".
Entergy System Planning & Operations (Gen & Mktg)	No	The RC should be aware of SOL exceedances in order to perform their function and maintain situational awareness.
Entergy Services	No	SOLs should be removed. While certain SOLs may need to be communicated to the RC per internal processes, only IROLs should be required to be reported. Reporting of every SOL could "water down" the communications to the RC and add confusion when IROLs are reported.
Independent Electricity System Operator	Yes	SOLs are intended to ensure reliable operation of the BES. TOPs, who calculate these SOLs to begin with, shall not intentionally operate its system to be very near or exceeding SOLs. Thus, we do not expect SOL exceedences to occur so frequently that reporting to the RC will create an overload of messages.
Northeast Utilities	No	We do not believe that the TOP informing the RC of every SOL exceedance should be required, and would not facilitate preserving reliability. Suggest removing "or SOL" from the requirement.
Duke Energy	Yes	R5 should be revised to also require the TOP to notify the RC of the particular IROL or SOL that has been exceeded.
AEP	Yes	The TOP-001-1 purpose statement deals with emergencies and taking actions to resolve them. The TOP-001-2 purpose statement deals with coordination. We concur that notifying the RC of every SOL violation could be overwhelming and counter productive to reliability. If SOL are to be reported then some prioritization needs to be given. We suggest reporting the largest SOL if there are several common to an area of congestion.
Response: This question was poorly worded and as a result the commenters may have been led astray. The consensus of the industry at this point is that not all SOLs need to be reported but that some subset of them should. The SDT will re-phrase the question in the second posting so that the intent is clear and so that a definitive position on the issue can be established.		
Bonneville Power Administration	No	Agree that it would increase workload while trying to return the system within limits. This requirement should probably move to TOP-004-3. R6 should maybe move there also as Real-Time Operations?

Organization	Yes or No	Question 3 Comment
Response: The SDT believes that it could be moved and be equally effective however this is the only comment received on this matter so the SDT is not going to make a change.		
American Transmission Company	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your response.		

4. TOP-002-3 Requirement R1 uses the new proposed term Simulated Contingency. The term's use is intended to clarify that the Contingencies used in the next day assessment are intended to model Contingencies that could occur based on the projected System topology and not Contingencies that have actually occurred on the System. The SDT is concerned that the definition may inadvertently lead the reader to believe that a power System simulator is required. Do you believe that the definition and term accomplish the intention of clarifying TOP-002-3 Requirement R1 without confusing the reader into believing a power System simulator is required? If not, please suggest alternative wording for TOP-002-3 Requirement R1 that communicates the SDT's intent.

Summary Consideration:

After review of all comments received, the SDT believes that the addition of the definition is not necessary. Accordingly, the definition will be eliminated and the wording of TOP-002-3, Requirement R1 has been revised accordingly.

TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Organization	Yes or No	Question 4 Comment
NPCC	No	Change the definition of Simulated Contingencies to: "The act of using planning and operating models to replicate Contingency responses."
Santee Cooper	No	Don't believe the current definition implies that a simulator is required. However, the definition of Simulated Contingency is not clear and very ambiguous. Suggested definition for Simulated Contingency is a contingency evaluated using planning and operating models of the BES.
Oncor Electric Delivery	No	"Study Contingency" may be a better choice and would remove the possible link between simulator and simulated contingency
American Transmission Company	No	The phrase "Simulated Contingency" should be replaced with a more concrete concept. ATC suggest that the SDT link the requirement to FAC-011. The purpose of FAC-011 is to ensure that SOLs used in the reliability operations of the BES are determined based on an established SOL methodology.
Response: The definition was intended to indicate that, although studies are not required for an assessment, the assessment should include all expected results from the System response to Contingencies which had been modeled in the development of System Operating Limits. The methodology of developing the SOLs includes the Contingencies that are to be considered in the development of those limits. The SDT has revised the wording of Requirement R1 to simplify and clarify		

Organization	Yes or No	Question 4 Comment
expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
SERC OC Standards Review Group	No	For additional clarification, we suggest the following alternative wording for the Definition of Simulated Contingencies: "The act of using planning and operating models to model single branch or unit outages in the modeled network."
Duke Energy	No	We believe that the definition of Simulated Contingencies should be revised as follows: The act of using planning and operating models to model single branch or unit outages in the modeled network.
Response: The SDT feels that the information you suggest is addressed in the required methodology to be used in the development of System Operating Limits**.** The definition was intended to indicate that, although studies are not required for an assessment, the assessment should include all expected results from the System response to Contingencies which had been modeled in the development of System Operating Limits. The methodology of developing the SOLs includes the Contingencies that are to be considered in the development of those limits. The SDT has revised the wording of Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
PJM Interconnection	No	The definition needs more work to avoid confusion. The word "simulated" will itself likely be a point of contention. One solution would be to delete the word "simulated". If this issue of post-contingency simulation becomes a problem, then a Standard Interpretation can be issued.
Southern Company Transmission	No	The proposed definition of "Simulated Contingency" is not clear. Also, it is not apparent why a new definition is even needed. Make the definition part of the requirement. Why couldn't ?Simulated? be replaced with something like "depicted", "represented" or "portrayed". Possible wording for the Requirement 1 might be ?The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOL's) during anticipated normal conditions and Contingency events represented through planning and operational analysis models reflecting design parameters and system conditions.? In the event the drafting team does not agree to implement our suggested change above, the drafting needs to address this issue also in IRO-004-01, R1 where the requirement states normal or anticipated contingency events and not "simulated events". The two requirements should be consistent in terms.
Bonneville Power Administration	No	Change the definition from "design considerations" to "planned outages".
Response: After reviewing all comments submitted, the SDT agrees that the definition seems to lack needed clarity The definition was intended to indicate that,		

Organization	Yes or No	Question 4 Comment
although studies are not required for an assessment, the assessment should include all expected results from the System response to Contingencies which had been modeled in the development of System Operating Limits. The methodology of developing the SOLs includes the Contingencies that are to be considered in the development of those limits. The SDT has revised the wording of Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
Dominion - Electric Market Policy	No	We suggest revising the stated purpose rather than creating a new definition. We suggest revising purpose to read " To ensure that reliability entities have coordinated plans for meeting expected operating conditions including contingencies that could occur based on projected system topology."
Response: The SDT believes that the existing purpose statement is appropriate and that required methodologies for determination of system operating limits include the concept of contingencies that could occur and the projected system topology**.** After reviewing all comments submitted, the SDT agrees that the definition seems to lack needed clarity The definition was intended to indicate that, although studies are not required for an assessment, the assessment should include all expected results from the System response to Contingencies which had been modeled in the development of System Operating Limits. The methodology of developing the SOLs includes the Contingencies that are to be considered in the development of those limits. The SDT has revised the wording of Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
Midwest ISO Stakholders Standards Collaborators	No	Why can't you just use the term potential in front of Contingency?
ITC Transmission	No	Suggest using the phrase "potential contingency" rather than "simulated contingency".
ISO-NE	No	We suggest using the term "potential contingencies" and avoid coming up with a new definition. The proposed definition is unclear and will lead to confusion.
IRC Standards Review Committee	No	We suggest using the term "potential contingencies" and avoid coming up with a new definition. The proposed definition is unclear and will lead to confusion.
AEP	No	The "Simulated Contingency" definition lacks clarity and its use in TOP-002-3 R1 does imply that an offline load flow program would be required when conducting a next day assessment. Suggested wording: Replace "and Simulated Contingency" with "and/or potential contingency".

Organization	Yes or No	Question 4 Comment
Response: After reviewing all comments submitted, the SDT agrees that the definition does not lend added clarity. Your suggestion is a good one. The SDT has revised the wording of TOP-002-3, Requirement R1. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
FirstEnergy	No	We believe that the definition is not needed and that the use of the word "simulated" in and of itself provides sufficient clarity that the requirement does not refer to actual Contingency events. The premise of the requirement is an assessment of "next day" system condition so it is unclear how this could in anyway be construed to be an actual contingency event. However, what is not clear in the requirements is what type of contingencies are to be evaluated? Is it single Contingency (N-1) events only. What if bus faults were not studied would there be a potential for non-compliance? There should be some tie to the TPL standards to specifically identify which Contingencies must be evaluated for Next Day analysis.
Ameren	No	This change is not necessary. The "Contingency" definition is for things that could but are not certain to happen. Obviously, there is no basis for a contingency that has occurred. Once occurred, it is an event.
Response: After reviewing all comments submitted, the SDT agrees that the definition is not needed. The SDT has revised the wording of TOP-002-3, Requirement R1. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* As to what type of Contingency must be considered, the Transmission Operator is not limited to single Contingencies or bus faults but must study any and all conditions that may result in exceeding any of its System Operating Limits during anticipated normal conditions as stated in the Requirement. The potential Contingencies to be studied are limited to those spelled out in the TPL standard.		
Entergy Services	No	There can be much confusion with the standards when terms are used in multiple ways. The poster child for this is "critical facilities." I agree with the intent of the SDT, but suggest the term "Postulated Contingencies."
Independent Electricity System Operator	No	We do not see the need to define this new term. Further, the definition is inaccurate (mixing contingency which is a "what-if" event with system response) and confusing (we are unable to understanding the meaning of "the net effect of design considerations" in an operational planning assessment domain. Having said that, we do not interpret the term to mean the requirement for a "simulator". To eliminate the concern of misinterpretation, we suggest that R1 be reworded to "? during anticipated normal conditions and analyzed contingency events."
Response: After reviewing all comments submitted, the SDT believes that use of the term "potential Contingencies" is appropriate. The SDT will revise the wording		

Organization	Yes or No	Question 4 Comment
of TOP-002-3, Requirement R1 to simplify and clarify. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*.		
Northeast Utilities	No	Suggest adding the words "such as P/SSE, power flow, etc." to the definition after the word "models". This might help to clarify the intent. Ending the definition after the word "responses" would make it a cleaner definition. Additionally, the defined term is "Simulated Contingencies". R1 uses the term "Simulated Contingency". This should be reconciled by either changing the defined term, or R1 should use the defined term and drop the word "events" from the end of the sentence.
Response: After reviewing all comments received, the SDT believes the definition does not lend needed clarity. Further, the SDT recognizes that an assessment does not necessarily require a study to be performed each time the assessment is made. The SDT agrees that a robust underlying power flow study or model effort may be a good basis for an assessment, but is not required in all cases. After reviewing all comments submitted, the SDT believes that use of the term "potential Contingencies" is appropriate. The SDT has revised the wording of TOP-002-3, Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
MRO NERC Standards Review Subcommittee	Yes	
Consumers Energy Company	Yes	
Entergy System Planning & Operations (Gen & Mktg)	Yes	The definition of "Simulated Contingency" provides enough clarity to avoid confusion.
Response: Thank you for your response. Note that most commenters indicated that the definition wasn't needed or was unclear. After reviewing all comments submitted, the SDT believes that use of the term "potential Contingencies" is appropriate. The SDT has revised the wording of TOP-002-3, Requirement R1 to simplify and clarify expectations. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		

5. TOP-004-2, Measure M1: The SDT has adopted the position for this measure and others like it that the absence of an IROL Violation Report is a sufficient measure as opposed to retaining massive amounts of data for later audit. Do you agree with this assessment? If not, please provide specific suggestions for improvement.

Summary Consideration:

The consensus of comments received from industry is in agreement with the SDT position so no changes were made.

Organization	Yes or No	Question 5 Comment
MRO NERC Standards Review Subcommittee	No	This question is not consistent with TOP-004-2 M1, you either need the report or the data. You should be able to prove compliance with the report, stating absence of an IROL Violation Report in the question does not make sense.
Independent Electricity System Operator	No	First of all, we do not agree with the removal of SOL from R1 so we do not agree with M1.On the approach the SDT is proposing, we do not agree with the rationale that the absence of an IROL violation report is a sufficient measure. We believe the TOP should be required to provide evidence to demonstrate compliance (in this case, the data showing operating within IROL and Tv).
Response: If there has been no IROL violation, then there will be no violation data. The SDT believes that requiring retention of massive amounts of normal operating data does not make sense. The SDT believes that IROL Violation Reports, and the required supporting information, serves the purpose. Absence of the report indicates there has been no violation.		
Bonneville Power Administration	Yes	SDT has cleaned up TOP-004-3 well, removing duplicate requirements from other standards. I don't believe R2 (Agreements of switching) is necessary since TOP-001-2 R3 appears to cover assisting to mitigate emergencies/IROLs. It seems to me TOP-001 R5 and R6 are also real time operations and should go to TOP-004-3 has R2 and R3.
Response: The SDT believes that you have raised a legitimate point on TOP-004-3, R2 and will raise a question in the next posting to see what the industry feels on this topic**.** The SDT believes that it could be moved and be equally effective however this is the only comment received on this matter so the SDT is not going to make a change		
ISO-NE	Yes	We agree that having evidence of proof for non-events does not make sense. These are event-triggered standards and the focus should be to have evidence of compliance when an event in which compliance was required occurred. Some

Organization	Yes or No	Question 5 Comment
		would argue that evidence is needed because a TOP could fail to report an event. It should be kept in mind that a TOP that fails to report a violation would also be able to manipulate data to show continuous compliance.
IRC Standards Review Committee	Yes	We agree that having evidence of proof for non-events does not make sense. These are event-triggered standards and the focus should be to have evidence of compliance when an event in which compliance was required occurred. Some would argue that evidence is needed because a TOP could fail to report an event. It should be kept in mind that a TOP that fails to report a violation would also be able to manipulate data to show continuous compliance.
NPCC	Yes	We agree that having evidence of proof for non-events has no value. The focus should be to have evidence of compliance for instances when an event in which compliance was required occurred.
Santee Cooper	Yes	
SERC OC Standards Review Group	Yes	
PJM Interconnection	Yes	
Dominion - Electric Market Policy	Yes	
Southern Company Transmission	Yes	
Midwest ISO Stakholders Standards Collaborators	Yes	
FirstEnergy	Yes	
ITC Transmission	Yes	
Manitoba Hydro	Yes	
Consumers Energy	Yes	

Organization	Yes or No	Question 5 Comment
Company		
Ameren	Yes	An absence is sufficient.
Oncor Electric Delivery	Yes	
Entergy System Planning & Operations (Gen & Mktg)	Yes	
Entergy Services	Yes	
Duke Energy	Yes	
Northeast Utilities	Yes	We agree that having evidence of non-events has little value.
American Transmission Company	Yes	
Response: Thank you for your response.		

6. The SDT has included VRFs and Time Horizons with this posting. Do you agree with the assignments that have been made? If not, please make specific suggestions for improvement.

Summary Consideration:

While the SDT appreciates the perspective of comments for increasing the proposed Violation Risk Factors for various Requirements, the position taken by the SDT was to recognize that these standards represent not best practices, but the threshold of performance below which warrants penalties; including the potential for very severe penalties. The SDT, therefore, drafted and continues to support the position that only non-performance which, in itself, creates an adverse impact on reliability warrants a high VRF. Further, specific non-performance which may exacerbate (but not cause) an adverse impact on reliability generally may not warrant a high VRF because absent the non-performance in the primary area of concern, an adverse impact to reliability would not exist or would be minimal.

In each case, the SDT adopted the most appropriate level of risk assignment. This was done considering the following:

1. Direct correlation of adverse impact to reliability through non-performance of the specific requirement,
2. Whether non-performance of the specific requirement represented less-than-best practice as opposed to or compared with inadequate performance that represents dereliction of duty or imposing burden on others and which warrants penalty (i.e., performance which is merely less than best practice, but still adequate for reliability should not create or exacerbate risk)
3. The timing or urgency for which the adverse impact to reliability could occur

The following changes were made due to industry comments:

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions

TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

TOP-002-3, R2: The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

TOP-002-3, R3: The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

TOP-003-1, R5: Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

Organization	Yes or No	Question 6 Comment
NPCC	No	TOP-001 - all VRFs but R4 should be HIGH (change R5 and R7). TOP-002 - raise R1 from Low to Medium. It is more than just an administrative requirement.
PJM Interconnection	No	TOP-001 - all VRFs but R4 should be HIGH (change R5 and R7) TOP-002 - raise R1 from Low to Medium some type of OPB assessment is required, it is more then just an administrative requirement.
Response: TOP-001: With no reasons provided for the suggested changes, the SDT doesn't have any basis for making these changes. TOP-002-3, R1**:** The SDT agrees. The VRF for Requirement R1 has been changed to Medium. The presumption was that while the TOP is required to meet R1 and, therefore, need not have additional requirements to tell *HOW* Requirement R1 is met. However, comments prompted further consideration. It is apparent that adjacent entities would not be able to meet Requirement R1 without information otherwise unknown to them. That lack of information in the Operations Planning timeframe could cause that planning to be flawed. Therefore, the SDT is increasing this VRF from low to medium. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
SERC OC Standards Review Group	No	For TOP-001, R1, R2, R4 - the risk factor should not be the same for each time horizon shown. i.e., for operations planning, same day operations, real-time operations. We suggest R5 should have a Low VRF. For TOP-002-3, the time horizon for each of these requirements (R1-R3) should be "Operations Planning".
Response: The SDT did not see a need for a different VRF for each Time Horizon. R5 **-** The SDT disagrees. It is important to advise the Reliability Coordinator of actions being taken to restore limits, etc. Absent such reporting and coordination, the chances increase that the RC may direct others to take actions which are either duplicative or counter to the actions being taken by the TOP to restore operations to within limits. Minimally, informing the RC of actions would enable the RC to assure that the event does not escalate. The risk created by not informing the RC of actions being taken warrants higher than a low VRF. TOP-002-3: The SDT agrees. The Time Horizons for Requirements R1 – R3 have been changed to Operations Planning. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* **TOP-002-3, R2:** The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">TOP-002-3, R3: The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). [Violation Risk Factor: High] [Time Horizon: Operations Planning]</td></tr>
<tr><td>Dominion - Electric Market Policy</td><td>No</td><td>TOP-001-2We believe that R5 and R7 warrant high VRF.

TOP-002-3 R1 warrants something higher than low. How can the TOP meet the intent of R2 (VRF = high) if it has failed at R1? We suggest that R1 and R2 should be high.

R3 should be reduced to low since the RC is required by IRO-004-1 @R3 to develop action plans in conjunction with its TOPs. The heavier burden should be placed on the RC.

The time horizon for R1-3 should be changed to Operations Planning</td></tr>
<tr><td colspan="3">Response: TOP-001-2: With no reasons provided for the suggested changes, the SDT doesn’t have any basis for making these changes

TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. However, comments prompted further consideration. It is apparent that adjacent entities would not be able to meet Requirement R1 without information otherwise unknown to them. That lack of information in the Operations Planning timeframe could cause that planning to be flawed. Therefore, the SDT is increasing this VRF from low to medium.

TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day’s operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

TOP-002-3, R3: The SDT disagrees. While the burden for “bigger picture” (i.e., the heavier burden) may rest on the RC, communications are required from the TOP for any expected performance or awareness by any other entity included in the plan (includes RC). If conflicting performance expectations occur, or there is a need to revise plans based on the RC review of all respective TOPs plans, then these should be resolved by the RC, as noted in the cited IRO standard. But absent the sharing of this information, it s not clear how others (including the RC) would be made aware of plans (which can then be coordinated among TOPs by the RC as needed).

TOP-002-3: The SDT agrees. The Time Horizons for Requirements R1 – R3 have been changed to Operations Planning.

TOP-002-3, R1: The Transmission Operator shall have an assessment for the next day’s operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

TOP-002-3, R2: The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

TOP-002-3, R3: The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). [Violation Risk Factor: High] [Time Horizon: Operations Planning]</td></tr>
<tr><td>FirstEnergy</td><td>No</td><td>The VRF for TOP-001-2 R7 should be a "High." Failure to follow the most conservative limit in times of uncertainty could negatively impact real-time reliability.</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
		The VRF for TOP-002-1 R4 seems inconsistent. It has a qualifying concept of urgency of time in the phrase "? unless System conditions do not permit such coordination." which implies critical to the reliability of the BES yet it has been assigned a Medium VRF. Also, failure to coordinate an action may not always result in an impact on the BES, but the action does in theory bear a risk to the reliability of the BES. This VRF should be a High. The VRFs for TOP-002-3 seem inconsistent. Requirement 2 which requires planning to mitigate a potential IROL discovered in the study required under R1 has a High VRF while R1 which requires the study be done has a Low. It is difficult to understand how a source requirement such as R1 can have a lower VRF then a derivative requirement such as R2. R1 and R2 should both have Medium VRFs since they are planning in nature and do not have an immediate impact on the BES. The VRF for TOP-003-1 R4 and R5 seem inconsistent. The drafting team appears to consider it a Medium risk for an entity not to supply operating data to its Transmission Operator, but a Low risk for that Transmission Operator not to supply the operating data to an entity "with immediate responsibility for operational reliability." The VRF for R5 should also be a Medium.
Response: TOP-001-2, R7**:** The SDT has deleted Requirement R7 as duplicative of IRO-05-3, Requirement R10. TOP-002-3, R4: There is no Requirement R4. TOP-002-3, R1**:** The SDT agrees. The VRF for Requirement R1 has been changed to Medium. However, comments prompted further consideration. It is apparent that adjacent entities would not be able to meet Requirement R1 without information otherwise unknown to them. That lack of information in the Operations Planning timeframe could cause that planning to be flawed. Therefore, the SDT is increasing this VRF from low to medium. TOP-002-3, R2: The SDT disagrees. Since IROLs are involved, the SDT feels that by definition the VRF must be high. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* TOP-003-1, R4 & R5: The SDT agrees. The VRF for Requirement R5 has been changed to Medium. **TOP-003-1, R5**: Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*		
ISO-NE	No	TOP-001R1: A High VRF may not be appropriate in all cases. There are some directives that relate to local limits that would by no means result in cascading outages or instability. Perhaps the VSL matrix should assign a low VSL for non IROL directives. R2: We are unable to assess the VRF for this requirement since we do not understand the meaning of "?.potential impacts

Organization	Yes or No	Question 6 Comment
		caused by disconnections prior to switching." R3: We do not necessarily agree with a High VRF for the same reason as for R1, unless the VSL matrix addresses the difference between extreme events and local issues. TOP-002R1: We suggest raising the VRF for R1 to a Medium. TOP-003R5: Should perhaps be elevated to Medium if the measure were more specific. An entity can't prove the negative (prove you've provided data to every entity that requested it). The measure and VSL should deal with a complaint being submitted by an operating entity that did not get the data it needed and requested.
IRC Standards Review Committee	No	TOP-001R1: A High VRF may not be appropriate in all cases. There are some directives that relate to local limits that would by no means result in cascading outages or instability. Perhaps the VSL matrix should assign a low VSL for non IROL directives. R2: We are unable to assess the VRF for this requirement since we do not understand the meaning of "?.potential impacts caused by disconnections prior to switching." R3: We do not necessarily agree with a High VRF for the same reason as for R1, unless the VSL matrix addresses the difference between extreme events and local issues. TOP-002R1: We suggest raising the VRF for R1 to a Medium. TOP-003R5: Should perhaps be elevated to Medium if the measure were more specific. An entity can't prove the negative (prove you've provided data to every entity that requested it). The measure and VSL should deal with a complaint being submitted by an operating entity that did not get the data it needed and requested.
Independent Electricity System Operator	No	TOP-001R1: We do not agree with a High VRF. Not complying with the TOP's directives does not necessarily result in cascading outages or instability. And since the responsible entities are allowed to not comply with the directives for safety and other reasons, we are unable to rationalize how impactive a risk can be when an entity violates this requirement. R2: We are unable to assess the VRF for this requirement since we do not understand the meaning of "?.potential impacts caused by disconnections prior to switching." R3: We do not agree with a High VRF for the same reason as for R1, viz. if provisions for not complying is given, how high a risk it is if a responsible entity violates this requirement? TOP-002R1: We suggest raising the VRF for R1 to a Medium. Day ahead operational assessment of system conditions against established limits is essential in ensuring sufficient resources are available and operational plans are in place to prevent exceeding limits and to provide mitigating measures when such exceedence occurs. This assessment uses established limits and as such, is equally impactive, if not more impactive, than developing the limits themselves.

Organization	Yes or No	Question 6 Comment
		TOP-003R5: We do not agree with a Low VRF assigned to this requirement whose intent is essentially the same as R4 except R5 goes beyond the local TOPs and BAs to the adjacent or higher level entities, which also need this data to ensure reliable operation. We suggest this VRF should be Medium - the same for R4.
Response: TOP-001-2, R1**:** The SDT disagrees. Directives should be followed. What is described here by the commenter is a need to provide better directives… but if a directive is given it must be presumed in Real-time to be needed, and must be followed. As appropriate after the fact, a review of the directive can be made with a goal toward higher quality directives. But in Real-time the SDT position is that if directives are not followed, a high risk to reliability is likely. Therefore, the SDT disagrees with the comment and no change has been made. TOP-001-2, R2: The intent of the phrase was to note one of the areas especially necessary to communicate (i.e., the opening of Interconnections or connections to generators, areas, etc). This is one of many things that need to be communicated if System conditions permit. Since this specific phrase was confusing to some, and since it describes only one of many possible conditions, the SDT has deleted the phrase. **TOP-001-2, R2:** Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions**.** TOP-001-2, R3: The SDT disagrees and has left the VRF as is. If emergency assistance is requested it should be rendered if available. If it is requested for improper reasons or is found to be a convenience rather than a necessity, then such a finding should be dealt with after the fact. But during the emergency period, requests should be honored (if possible without threatening life or property, or violating laws or other regulations, standards, etc.). TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* TOP-003-1, R5: The SDT agrees. The VRF for Requirement R5 has been changed to Medium. **TOP-003-1, R5**: Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*		
Entergy Services	No	TOP-002-3 R1: VRF should be Medium since you can't do R2 or R3 without it. TOP-003-1 R5 - VRF should be Medium, the same as R4
Response: TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]* TOP-003-1, R5: The SDT agrees. The VRF for Requirement R5 has been changed to Medium.		

Organization	Yes or No	Question 6 Comment
TOP-003-1, R5: Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*		
Northeast Utilities	No	TOP-002 - Raise R1 from Low to Medium.
Response: TOP-002-3, R1: The SDT agrees. The VRF for Requirement R1 has been changed to Medium. **TOP-002-3, R1**: The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*		
American Transmission Company	Yes	
Santee Cooper	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Subcommittee	Yes	
ITC Transmission	Yes	
Montenay Power Corp.	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	

Organization	Yes or No	Question 6 Comment
Oncor Electric Delivery	Yes	
Duke Energy	Yes	
Response: Thank you for your response.		

7. The SDT has included Measures and Data Retention with this posting. Do you agree with the assignments that have been made? If not, please make specific suggestions for improvement.

Summary Consideration:

While the majority of the commenters agreed with the parameters, the following changes have been made due to industry comments:

Since the data retention for all requirements was the same in TOP-001-2, the data retention requirements for each requirement and measure were deleted and replaced with the following:

TOP-001-2, data retention: The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

TOP-002-3, M1. The Transmission Operator shall have evidence that it has assessed next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

Since the data retention for all requirements was the same in TOP-002-3, the data retention requirements for each requirement and measure were deleted and replaced with the following:

TOP-002-3, data retention: The Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

TOP-004-3, M2: Each Transmission Operator shall make available evidence that it has Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2. Such evidence could include but is not limited to a dated document with confirmation of the Agreement, such as a signature page or a memorandum of understanding, in electronic or hard copy format.

Organization	Yes or No	Question 7 Comment
NPCC	Yes	NPCC participant members agree provided that only the data specified is required to be dated, not the actual data.
Response: The SDT feels that your comment is covered in TOP-003-1, R1.2 which states “a mutually agreed upon format” between the two entities. The specifics of the request for information will be agreed upon by the parties involved and dated accordingly**.**		
Santee Cooper	No	OK with the measures and data retention with the exception of our concerns discussed in Question 12.
Response: Thank you for your response and please see the response to question 12.		

Organization	Yes or No	Question 7 Comment
SERC OC Standards Review Group	No	If the changes suggested above are agreed to by the SDT, please make the appropriate corresponding changes to the measurements.
Independent Electricity System Operator	No	We do not agree with some of the requirements (see above) and hence do not agree with some of the Measures. Other than that, we generally agree with the measures and retention periods for those requirements that we agree with.
Response: Please see the above responses.		
PJM Interconnection	No	TOP-003 M1-M5 - they all introduce a new requirement (i.e. the report be dated) - that requirement should be dropped from the measures.
Response: M1 **-** The SDT believes that it is imperative to have dated documentation pertaining to all reliability related information that is passed on between operating entities. This is particularly true whenever system upgrades/changes are done or equipment ratings are changed. Adding the word 'dated' to the Measure does not alter the requirement and is only common sense. M2 – M5: 'Dated' is only employed here with respect to the use of operator logs as a type of evidence. This does not alter the requirement in any fashion and is simply a common sense statement.		
Dominion - Electric Market Policy	No	TOP-001-2 @M4 - We don't agree with the underlying requirement (see comment to question 12). We do not agree with data retention requirements for M1 and M3 this standard. In our mind, there are two tenants that must be honored above all. The first is to follow reliability directives whenever possible, the 2nd is to provide data necessary for reliability assessments. Where an entity fails to comply, the requestor should immediately file a complaint with the region or NERC. We expect either of these to perform a prompt review. So, we don't see the need to keep data for a year nor do we see value in keeping data until next compliance audit when found non compliant. TOP-002-3 @ M3 should be removed as we do not agree with underlying requirement (see comment to question 12).
Response: The SDT feels your comment about TOP-001-2, M4 really pertains to TOP-001-2, R4. The SDT believes that this requirement is necessary in order to keep other entities appraised of the status of a generator or plant when that status can directly impact the reliability of the BES. In many cases the RC or BA is not directly responsible for voltage control in a particular area. The TOP in these cases would most likely be the responsible party for monitoring and responding to area voltage concerns. If the GOP were not to advise the TOP in these cases about unit voltage control capability changes it could certainly impact the reliability of the BES. The SDT does not feel that measures M1 and M3 of TOP-001-2 are only associated with conditions of non-compliance. The measures are there to insure that entities simply show that they either complied with a directive or offered emergency assistance. If they couldn't comply for any of the reasons stated in Requirements R1 or R3 of TOP-001-2 they can show proof as to the reason why. The data retention times for both of these measures seems agreeable by all other responders, therefore		

Organization	Yes or No	Question 7 Comment
the SDT will retain the retention periods as stated in the draft. The SDT feels your comment about TOP-002-3, M3 really pertains to TOP-002-3, R3. The SDT feels this requirement is necessary to insure all entities help in addressing a potential IROL limit and that each entity knows their specific role in the plan. The requirement and measures will remain as drafted.		
MRO NERC Standards Review Subcommittee	No	1. The measures seem to repeat the requirements perhaps this could be avoided since additional detail in the measures are not enforceable only the requirements are. 2. In the standard TOP-001-2 the retention period for requirement 5 and measure 5 is longer than required for R1 through R4, what is the reasoning for this? 3. In the standard TOP-001-2, there is no retention period given for requirement 6 and measure 6.4. In all of the standards and in the last sentence of the section "1. 4 Data Retention", isn't it extreme to retain "all" requested and submitted subsequent audit records? 5. In the standard TOP-002-3, requirement 3 depends on requirement 2 but these requirements don't have the same retention period, should they? 6. Measure 5 of the standard TOP-003-1 references requirement 9, shouldn't it reference requirement 5? 7. In the standard TOP-003-1, the retention periods for R4/M4 and R5/M5 are only for 90 calendar days but the rest of the requirements have a retention period for 3 years, shouldn't R4/M4 and R5/M5 have the same retention period as the rest of the requirements in this standard? 8. The MRO has concerns about storing large amounts of real-time data. In TOP-003-01, should R1, R4, and R5 data retention be set at 90 days? 9. In the standard TOP-004-3, M2's last sentence references the text "confirmation". What is needed for confirmation? Would a signature page be an example?
Response: 1. The SDT feels that the measures simply reinforce the requirements and explains what is needed for compliance. 2. The SDT has changed the data retention requirements in TOP-001-2 to the same timeframe (current calendar year plus previous calendar year) for all requirements for consistency purposes. **TOP-001-2, data retention:** The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~. 3. The SDT has changed the data retention requirements in TOP-001-2 to the same timeframe (current calendar year plus previous calendar year) for all requirements for consistency purposes.		

Organization	Yes or No	Question 7 Comment
4. The interpretation of the SDT on "all" requested and submitted subsequent audit records" means any supporting data required to be provided following a compliance audit. This would be a reasonable request, and that data should be kept with the original audit records. 5. The SDT agrees that all data retention requirements in TOP-002-3 should be the same. **TOP-002-3, data retention**: The Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. 6. The SDT has already taken care of this and the change has been made. Thank You for the comment. 7&8. The data retention periods for TOP-003-1 have been changed so that they are all the same - 3 calendar years (except for Requirement/Measure 1). The SDT feels a signature page would be acceptable and has changed the standard accordingly. **TOP-004-3, M2**: Each Transmission Operator shall make available evidence that it has Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2. Such evidence could include but is not limited to a dated document with confirmation of the Agreement, such as a signature page or a memorandum of understanding, in electronic or hard copy format.		
ITC Transmission	No	In TOP-001, the majority of retention requirements are current year plus one, except one is 3 years and one isn't specified. All retention requirements in this standard should be the same. In TOP-002 M1 add operating plans or guides as evidence that an assessment was performed. In TOP-002 retention requirements should be the same for all requirements.
Response: The SDT will change the data retention requirements in TOP-001-2 for all 6 requirements to the same timeframe for consistency purposes (current calendar year plus previous calendar year). **TOP-001-2, data retention:** The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~. The SDT feels that operating plans or guides are not required in TOP-002-3, M1. TOP-002-3, R1 simply states that the TOP needs to do an assessment for the next days operation to identify any potential SOL's . If there are no potential SOL's identified in the assessment then there is no need for plans or guides on how to address SOL's.		
ISO-NE	No	In general, TOP-001 is an event triggered standard. For example, a limit is violated and not corrected, an entity failed to followed a directive, etc.. Since it's impossible to prove the negative when there isn't an event, what these measures will

Organization	Yes or No	Question 7 Comment
		cause is entities to pass requests around to get statements from others to have something to show an auditor. TOP-003 It should be acceptable (rather that keeping evidence that each entity was sent a specification) that the specification be available to an accessible site and that the entities were made aware of its location. The measures should revolve around failure to obtain or provide data and either an event occurred or a complaint arose.
IRC Standards Review Committee	No	In general, TOP-001 is an event triggered standard. For example, a limit is violated and not corrected, an entity failed to followed a directive, etc.. Since it's impossible to prove the negative when there isn't an event, what these measures will cause is entities to pass requests around to get statements from others to have something to show an auditor. TOP-003 It should be acceptable (rather that keeping evidence that each entity was sent a specification) that the specification be available to an accessible site and that the entities were made aware of its location. The measures should revolve around failure to obtain or provide data and either an event occurred or a complaint arose.
Response: The SDT believes that all the measures in TOP-001-2 are appropriate and should easily be able to be complied with for auditing purposes. If an entity is asked to follow a directive or help in some way during an emergency those directives and conversations should be documented and most likely recorded. Even if there were not an event on the System, the SDT feels that all directives and requests between entities should be required to be written down at a minimum and therefore should be easy to retain for proof at a later time if needed. The SDT believes that mandating all entities to forward all required data specification information to one site is beyond the scope of the SDT. The measures do in fact revolve around failure to obtain or provide data. The SDT will make no changes to TOP-003 based on these comments.		
Manitoba Hydro	No	TOP-001-2. Data retention for all requirements should be the same. That is, current year plus the previous year.
Response: The SDT will change the data retention requirements in TOP-001-2 for all 6 requirements to the same timeframe for consistency purposes (current calendar year plus previous calendar year). **TOP-001-2, data retention:** The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.		
Ameren	No	There are inconsistencies in specified retention periods among several requirements. While we do not know the reason for this, we recommend that the SDT review the different retention periods and provide as much consistencies as possible.
Response: The SDT has reviewed the data retention requirements and made changes for consistency where necessary.		
Entergy Services	No	TOP-002-3 M1: We suggest a good example of compliance evidence be power flow models and study results instead of operator logs. If not, what does "assessment" mean in R1?

Organization	Yes or No	Question 7 Comment
Response: The SDT understands that the term assessment may mean different things to different entities. TOP-002-3, R1 indicates that the TOP needs to assess whether normal or Contingency conditions for the next day may exceed an SOL. Generally speaking this will only be known to the TOP through load flow studies and security analysis. TOP-002-3, M1 states "Such evidence could include but is not limited to dated operator logs or reports". As for the evidence, the SDT agrees that power flow outputs and study results are more appropriate and has made that change. **TOP-002-3, M1**. The Transmission Operator shall have evidence that it has assessed next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.		
AEP	No	Refer to question 3 response. The TOP-001-2 three year data retention for SOL violations seems excessive. Data that has been retained this long tends to lose its value. We would like to hear an argument from the SDT how this improves system reliability. Similarly, the three year data retention for distributing data specifications in TOP-003-1 (R2/M2, R3, M3) also seems excessive. We propose that the current and previous calendar years would suffice.
Response: The SDT will change the data retention requirements in TOP-001-2 for all 6 requirements to the same timeframe for consistency purposes (current calendar year plus previous calendar year). **TOP-001-2, data retention:** The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~. The data retention periods for TOP-003-1 have been changed so that they are all the same.		
Northeast Utilities	Yes	
American Transmission Company	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 7 Comment
Montenay Power Corp.	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery	Yes	
Duke Energy	Yes	
Response: Thank you for your comments.		

8. The SDT has included compliance elements including VSL for this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for change.

Summary Consideration:

Due to industry comments, the SDT has changed the following requirements, measures, and VSLs:

TOP-001-2, R1: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each reliability directive issued by the Transmission Operator, unless the respective entity informs the Transmission Operator that such actions would violate safety, equipment, regulatory or statutory requirements.

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

TOP-001-2, R4: Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination.

VSL

TOP-001-2, R1:

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements

TOP-001-1, R3, Severe VSL: The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements.

TOP-001-2, R4 VSL:

R4	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with 25% or less of the affected reliability entities unless conditions did not permit such coordination	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 25% or less than or equal to 50% of the affected reliability entities unless conditions did not permit such coordination	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 50% or less than or equal to 75% of the affected reliability entities unless conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 75% of the affected entities unless conditions did not permit such coordination.

TOP-001-2, R6 VSL:

R6	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on one occasion.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on two occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on three occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on four or more occasions.

TOP-002-3, R3 VSL:

R3	The Transmission Operator did not notify 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

TOP-003-1, R2 VSL:

R2	The Transmission Operator did not distribute its data specification to 25% or less of the entities that has Facilities monitored by the Transmission Operator or to 25% or less of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 25% and less than or equal to50% of the entities that have Facilities monitored by the Transmission Operator or to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 50% and less than or equal to 75% of the entities that have Facilities monitored by the Transmission Operator or more than 50% and less than or equal to 75% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 75% of the entities that have Facilities monitored by the Transmission Operator or more than 75% of the entities that provide Facility status to the Transmission Operator.

TOP-003-1, R3 VSL:

R3	The Balancing Authority did not distribute its data specification to 25% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 50% and less than or equal to 75% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 75% of the entities that provide Facility status to the Balancing Authority

Organization	Yes or No	Question 8 Comment
Santee Cooper	No	OK with the VSLs with the exception of our concerns discussed in Question 12.
Response: Thank you for your response and please see the response to question 12**.**		
SERC OC Standards Review Group	No	TOP-001, R4. We suggesting changing the words "affect and affected" to "impact and impacted", respectively.

Organization	Yes or No	Question 8 Comment
Response: The SDT has changed the requirement. **TOP-001-2, R4:** Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination.		
Dominion - Electric Market Policy	No	TOP-001-2R1 - Could be interpreted that non-compliance is based on number of occasions whereby entity invoked safety, equipment, regulatory, or statutory requirements as opposed to number of occasions whereby entity failed to comply with reliability directives. Suggest revising to read "?.did not comply with reliability directives issued by the Transmission Operator and did not inform the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, on one occasion." Suggest use of similar language for each Severity Level. R3 - Suggest revising to read "The Transmission Operator, Balancing Authority, or Generator Operator did not render emergency assistance to others, as requested and did not inform the requestor that such actions would violate safety, equipment, regulatory, or statutory requirements. R4 - Revise to conform to comment in question 12. TOP-003-1 R4 - Do not agree that a any failure to provide data warrants severe. Is reliable operations jeopardized for failure to report an outage on a 10 Mw peaking CT as it is for a 1000 Mw base load unit? We don't see them as the same and would rather see something akin to the following: Low - Failed to provide > 25% of data required Moderate - failed to provide 26-50% of data required High - Failed to provide 51-75% of data required Severe - failed to provide > 75% of data required
Response: On TOP-001-2, R1, the SDT agrees with your suggestion and has made conforming changes to clarify that noncompliance is based on a single occurrence where directions were not obeyed except in those cases where the TOP was not informed of safety, equipment, regulatory, or statutory requirements that prevented compliance with the directives. We also removed the Lower, Moderate and High VSLs at the suggestion of ITC Transmission. **TOP-001-2, R1 VSL**:		

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive

Organization	Yes or No	Question 8 Comment
		issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements.
: On TOP-001-2, R3, the SDT agrees and has made conforming changes for the same reasoning as indicated in our response for TOP-001-1, R1, above. **TOP-001-1, R3, Severe VSL**: The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements. On TOP-001-2, R4: The SDT will ask a specific question of the industry on deleting the GOP from this requirement in the next posting. On TOP-003-1, R4, the SDT thanks you for your comment, but does not agree. The intent of this requirement is to guarantee that the TOP will have all the data necessary to perform Real-time monitoring and reliability assessments. As such, the data that is requested is either supplied or it isn't, creating a binary situation. Attempting to divine 4 levels of non-compliance in a binary situation results in imprecise boundaries and increased auditor discretion, both of which lead to regulatory uncertainty, which is what the SDT is attempting to minimize.		
Bonneville Power Administration	Yes	I think TOP-001-2 R6 would be better to say the TOP "shall act to ensure mitigation of the magnitude?" thus eliminating extraneous phrasing "direct others".
Response: The phrase "ensure mitigation" potentially introduces new obligations on the TOP via the compliance process, e.g., how would we measure that the TOP "ensured mitigation" when the term "ensure" means to essentially guarantee in all situations? Therefore, the SDT did not change the language of Requirement R6.		
FirstEnergy	No	The VSL for TOP-001 R1 should all be revised to state, "? The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, and the respective entity failed to inform the Transmission Operator that such actions would violate safety, equipment, regulatory,

Organization	Yes or No	Question 8 Comment
		or statutory requirements on (one, two, three, four or more) occasion. " The VSL for TOP-001 R3 should be revised to state, "The Transmission Operator, Balancing Authority or Generator Operator did not render emergency assistance to others, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements. The VSL for TOP-001 R4 should be revised in a similar fashion to R1 and R3 above. The VSL for TOP-002 R3 as written implies that an entity that interacts with only one reliability entity would not receive a violation greater than "lower." In addition, as written these VSLs seem to allow the Compliance Auditor the opportunity to choose how to apply the VSL. As an example the entity with one reliability entity could be found to be guilty of a "Lower" violation because they missed their one reliability entity or they could be guilty of a "Severe" violation because they missed 100% of their reliability entities. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity. The VSL for TOP-003 R2 as written implies that an entity that interacts with only one data supplier would not receive a violation greater than "lower." In addition, as written these VSLs seem to allow the Compliance Auditor the opportunity to choose how to apply the VSL. As an example the entity with one data supplier could be found to be guilty of a "Lower" violation because they missed their one data supplier entity or they could be guilty of a "Severe" violation because they missed 100% of their data supplier entities. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity. The VSL for TOP-003 R3 has the same problem as R2. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity. The VSL for TOP-004 R1 states, "The Transmission Operator did not operate within an identified Interconnection Reliability Operating Limits(IROL) and the associated IROL Tv for any single occasion." This should be changed to state, "The Transmission Operator failed to mitigate an identified Interconnection Reliability Operating Limits (IROL) and within the allotted IROL Tv for any single occasion. " The VSL for TOP-004 R2 as written implies that an entity with only 1 tie line would not receive a violation greater than "lower." In addition, as written these VSLs seem to allow the Compliance Auditor the opportunity to choose how to apply the VSL. As an example the entity with one tie line could be found to be guilty of a "Lower" violation because they missed their one directly connected entity or they could be guilty of a "Severe" violation because they missed 100% of their directly connected entities. Suggest the drafting team eliminate the first sentence of each of these VSLs and use percentages as the test of violation severity.

Response: On TOP-001-2, R1 and R3 VSL, the SDT made changes to accommodate industry concerns.

TOP-001-2, R1 VSL:

Organization	Yes or No	Question 8 Comment			
R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements	

TOP-001-1, R3, Severe VSL: The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements.

On TOP-001-2, R4, the SDT cannot determine your intent as to why the VSL for R4 should be revised, because the comment indicates that it should be revised "in a similar fashion to R1 and R3", yet, R4 does not have the clarifying clause that was the subject of the comments in R1 and R3. Therefore, no change was made with regard to binary VSL but wording changes for clarity have been made.

TOP-001-2, R4 VSL:

R4	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not

Organization	Yes or No	Question 8 Comment			
	coordinate their respective operations known or expected to impact other reliability entities with 25% or less of the affected reliability entities unless conditions did not permit such coordination	coordinate their respective operations known or expected to impact other reliability entities with more than 25% or less than or equal to 50% of the affected reliability entities unless conditions did not permit such coordination	coordinate their respective operations known or expected to impact other reliability entities with more than 50% or less than or equal to 75% of the affected reliability entities unless conditions did not permit such coordination.	coordinate their respective operations known or expected to impact other reliability entities with more than 75% of the affected entities unless conditions did not permit such coordination.	

On TOP-002-3, R3 the SDT agrees and has made appropriate changes.

TOP-002-3, R3 VSL:

R3	The Transmission Operator did not notify 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

On TOP-003-1, R2 and R3, the SDT agrees.

TOP-003-1, R2 VSL:

R2	The Transmission Operator did not distribute its data specification to 25%	The Transmission Operator did not distribute its data specification to more	The Transmission Operator did not distribute its data specification to more	The Transmission Operator did not distribute its data specification to more

Organization	Yes or No	Question 8 Comment			
	or less of the entities that have Facilities monitored by the Transmission Operator or to 25% or less of the entities that provide Facility status to the Transmission Operator.	than 25% and less than or equal to50% of the entities that have Facilities monitored by the Transmission Operator or to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Transmission Operator.	than 50% and less than or equal to 75% of the entities that have Facilities monitored by the Transmission Operator or more than 50% and less than or equal to 75% of the entities that provide Facility status to the Transmission Operator.	than 75% of the entities that have Facilities monitored by the Transmission Operator or more than 75% of the entities that provide Facility status to the Transmission Operator.	
TOP-003-1, R3 VSL:					
R3	The Balancing Authority did not distribute its data specification to 25% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 50% and less than or equal to 75% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 75% of the entities that provide Facility status to the Balancing Authority	

On TOP-004-3, R1, the SDT feels the suggested wording is basically equivalent to what is already there so no change was made.

On TOP-004-3, R2, the SDT is going to ask a question on the elimination of this requirement in the next posting so no changes have been made at this time.

Organization	Yes or No	Question 8 Comment
MRO NERC Standards Review Subcommittee	No	1. For the TOP-001-2 VSLs for R1, these VSLs should be reworded because complying to the requirement would meet those VSLs. The MRO would suggest replacing "unless" with an "and" plus change the trailing text to read "? the respective entity did not inform the transmission operator ?". 2. For the TOP-001-2 VSLs for R2, what about the situation where the transmission operator did inform the RC and the affected TOP of a real-time emergency condition on an occasion but the notification was after the disconnection of switches? 3. For the TOP-001-2 VSLs for R4, what if the TOP or GOP does not coordinate because of system conditions. Is it possible that those entities might disagree as to what is a system condition? How would this disagreement be handled? 4. For the TOP-001-2 VSLs for R6, the timing is only one element of the evidence. These VSLs should be rewritten because the VSLs add to the requirement. The VSL should be changed to replace "the timing of when it acted" with "its actions" plus, add the text "when it" between the words "or" and "directed others".

Response: On TOP-001-1, R1, the SDT has made this change.

TOP-001-1, R1 VSL:

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate

Organization	Yes or No	Question 8 Comment

				safety, equipment, regulatory, or statutory requirements

On TOP-001-2, R2, the SDT removed the phrase from the requirement which should alleviate the concern.

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

On TOP-001-2, R4, the SDT believes that the respective entity makes the determination but that they must be prepared to defend their actions on a case by case basis.

On TOP-001-2, R6, the RTOSDT agrees with your comment and has made conforming changes.

TOP-001-2, R6 VSL:

R6	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on one occasion.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on two occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on three occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on four or more occasions.

Organization	Yes or No	Question 8 Comment
ITC Transmission	No	TOP-001 R1 Failure to follow a directive one even one occasion without reason should be treated as a severe VSL, similar to R3. TOP-002 R1 & R2 VSL should not be severe, there should be VSLs at all levels. It is not logical to have a severe VSL for not performing a day ahead analysis, and a Lower VSL for not following a reliability directive. TOP-004 R4 should have VSL for all levels, similar to R2,R3

Response: On TOP-001-2, R1, the SDT has made changes accordingly.

Organization	Yes or No	Question 8 Comment

TOP-001-2, R1 VSL:

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements

On TOP-002-3, R1 and R2, the SDT agrees and has changed TOP-001-2, R1 VSL. .

In response to your final comment, there is no TOP-004-3, R4,

Organization	Yes or No	Question 8 Comment
ISO-NE	No	In general, these are binary requirements. An entity followed a directive or not, data was provided or it was not, a study was done or it was not. The true fix is to develop a sanctions matrix that deals with binary requirements rather than coming up with subjective ways to measure something that is yes/no. That said, we would not recommend spending a great deal of time making modifications, as there will most likely be an order directing modifications once the standard is filed.

Organization	Yes or No	Question 8 Comment
IRC Standards Review Committee	No	In general, these are binary requirements. An entity followed a directive or not, data was provided or it was not, a study was done or it was not. The true fix is to develop a sanctions matrix that deals with binary requirements rather than coming up with subjective ways to measure something that is yes/no. That said, we would not recommend spending a great deal of time making modifications, as there will most likely be an order directing modifications once the standard is filed.
Response: The SDT thanks you for your response.		
Manitoba Hydro	No	TOP-001-2 R5.. SOLs should be removed from the requirement and the VSLs.
Response: The SDT believes that the current wording is appropriate and no change was made.		
Ameren	No	1. For the TOP-001-2 VSLs for R4, what if the TOP or GOP does not coordinate because of system conditions. Is it possible that those entities might disagree as to what is a system condition? How would this disagreement be handled? 2. For the TOP-001-2 VSLs for R6, the timing is only one element of the evidence. These VSLs should be rewritten because the VSLs add to the requirement. The VSL should be changed to replace "the timing of when it acted" with "its actions" plus, add the text "when it" between the words "or" and "directed others".

Response: On TOP-001-2, R4, the SDT believes that the respective entity makes the determination but that they must be prepared to defend their actions on a case by case basis.

On TOP-001-2, R6, the RTOSDT agrees with your comment and has made conforming changes.

TOP-001-2, R6 VSL:

R6	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on one	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on two	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on three	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv on four or

Organization	Yes or No	Question 8 Comment

	occasion.	occasions.	occasions.	more occasions.

Organization	Yes or No	Question 8 Comment
Independent Electricity System Operator	No	a. We do not agree with some of the requirements, and suspect other commenters may express disagreements with some requirements. This may result in changes to the requirements and as such, the VSLs will need to be revised. b. A number of the VSLs proposed in the TOP standards, e.g. TOP-001, R1 and R2, are graded according to the number of repeated violations. This approach may need to be changed since recent FERC NOPR proposes that repeated violation is not to be the basis for different violation levels c. TOP-003, R1: It appears that missing one of the subrequirements is assigned a Low VSL, missing 2 of them is assigned a Medium VSL and missing all 3 or having no documented specification is assigned a Severe. We suggest to move the first 2 conditions to Medium and High.

Response:.

Understood.

The language of the requirement will determine if violations can be accumulated. If the requirement is plural, violations can be accumulated to assess the VSL. Without specific examples, the SDT cannot make specific changes.

On TOP-003-1, R1, the RTO SDT agrees with your suggestion and has made conforming changes.

TOP-003-1, R1:The SDT disagrees and has not made a change.

Organization	Yes or No	Question 8 Comment
Duke Energy	No	TOP-003-1 Requirement R5 VSLs should be patterned after the VSLs for Requirements R2 and R3, i.e. a graduated scale since R5 is not a binary requirement. TOP-002-3 Requirement R3 - if only one reliability entity is identified in plans to preclude exceeding an IROL, and that entity is not notified, which VSL would apply - "Lower" or "Severe"?

Response: The SDT continues to view Requirement R5 as a binary requirement, and did not change the VSLs per your suggestion.

On TOP-002-3, R3, the SDT has made changes to address your concern.

TOP-002-3, R3 VSL:

R3	The Transmission Operator did not notify 25% or less of the reliability	The Transmission Operator did not notify more than 25% and less than or	The Transmission Operator did not notify more than 50% and less than or	The Transmission Operator did not notify more than 75% of the

Organization	Yes or No	Question 8 Comment

	entities identified in the plan(s) cited as to their role in the plan(s).	equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	reliability entities identified in the plan(s) as to their role in the plan(s).

Organization	Yes or No	Question 8 Comment
American Transmission Company	No	TOP-001-2 VSL: VSLs for R1 and R2 are written for when an entity does not follow a directive multiple times. Per FERC VSL should be based on the single non-compliance event. ATC suggest that the VSLs be re-written based on FERC guidelines. VSLs for R5 and R6 are based on the entity not having evidence of compliance not on the fact that they did not comply with the requirement. ATC suggest that the VSL be rewritten in order to address the requirement not the evidence to support the requirement. VSL for TOP-002-3 Requirement 3: If in a plan you identify one reliability entity and fail to notify that entity what is the VSL level that will be assigned. This seems to fall in both Lower and Severe. ATC believes that the VSL's should only have a single method for determining the VSL level in order to prevent conflicting determinations.

Response: On TOP-001-2, R1, that SDT agrees and has made conforming changes to the VSLs. The language of the requirement will determine if violations can be accumulated. If the requirement is plural, violations can be accumulated to assess the VSL

TOP-001-2, R1: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each reliability directive issued by the Transmission Operator, unless the respective entity informs the Transmission Operator that such actions would violate safety, equipment, regulatory or statutory requirements.

TOP-001-2, R1 VSL:

R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the

Organization	Yes or No	Question 8 Comment

				Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements

On TOP-001-2, R2, however, the SDT disagrees that this is a binary requirement and did not change the VSLs.

On the VSLs for TOP-001-2, R5 and R6, the SDT understands your concerns, but without evidence of action, how can one prove compliance? The SDT sees no conflict between the VSLs as worded currently and the requirements.

On the VSL for TOP-002-3, R3, the SDT has made a change to address your concerns.

TOP-002-3, R3 VSL:

R3	The Transmission Operator did not notify 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

Organization	Yes or No	Question 8 Comment
NPCC	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 8 Comment
PJM Interconnection	Yes	
Consumers Energy Company	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your response.		

9. The SDT has provided an Implementation Plan with this posting. Do you agree with the implementation timeframes? If not, please provide specific suggestions for improvement.

Summary Consideration: The SDT feels that the Implementation Plan is well supported by the industry due to the fact there was only a single negative comment received. Therefore, the SDT will follow the timeframe for the Implementation Plan as drafted.

Organization	Yes or No	Question 9 Comment
SERC OC Standards Review Group	No	The SDT may want to consider a closer implementation date since there are no new requirements included in the proposed revisions to these standards.
Response: The RTO SDT feels the longer implementation dates are necessary in order to ensure that the projects mentioned in the prerequisites: Pre-2006, Operate within Interconnection Reliability Operating Limits; 2006-06, Reliability Coordination; and Project 2006-07, ATC/TTC/AFC and CBM/TRM Revisions have been approved prior to the implementation of this Project 2007-03, Real-Time Operations.		
Dominion - Electric Market Policy	Yes	While we agree with the SDT that all prerequisites must occur prior to implementation of this plan, we wish to cite, for the record, the sheer volume of draft standards that are now 'dependant' for prerequisite action on preceding drafts. We would like to see a moratorium on new drafts until the current back log is cleared. We are concerned that new drafts are being reviewed with the potential that ramifications of underlying/preceding drafts aren't being fully understood and/or that modifications made to any such drafts may not follow through in later draft standards predicated upon them.
Response: The SDT appreciates your concern but this is outside the scope of the SDT.		
NPCC	Yes	
Santee Cooper	Yes	
PJM Interconnection	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 9 Comment
FirstEnergy	Yes	
MRO NERC Standards Review Subcommittee	Yes	
ITC Transmission	Yes	
IRC Standards Review Committee	Yes	
Montenay Power Corp.	Yes	
PECO Energy		
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	
Oncor Electric Delivery	Yes	
Entergy System Planning & Operations (Gen & Mktg)	Yes	
Entergy Services	Yes	
Independent Electricity System Operator	Yes	We generally agree with the implementation timeframes that are dependent on the implementation of other standards. However, we reserve judgment on any specific issues that may arise when more definitive dates are proposed.
Duke Energy	Yes	

Organization	Yes or No	Question 9 Comment
AEP	Yes	
Northeast Utilities	Yes	
American Transmission Company	Yes	
ISO-NE	Yes	
Response: Thank you for your response.		

10. The SDT is recommending retirement of TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0. Do you agree with these retirements? If not, please provide specific reasons for your position.

Summary Consideration:

Due to industry comments, the following were changed:

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

TOP-003-1, Purpose: To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.

TOP-003-1, R1: Each Transmission Operator and Balancing Authority shall have a documented specification for data required to fulfill their respective responsibilities per the NERC Functional Model. The specification shall include:

TOP-003-1, R4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies).

TOP-003-1, M4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall make available evidence that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies) in accordance with Requirement R4. The data is limited to that needed by the Transmission Operator to support Operational Planning Analyses and reliability assessments. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

Organization	Yes or No	Question 10 Comment
NPCC	No	The note next to R4 in TOP-006 reads: "Load patterns now covered in the new TOP-005. Remainder not required for reliability." We understand that TOP-005 is to be retired, and we are unable to find the new TOP-005 that covers this requirement.
Independent Electricity System Operator	No	The note next to R4 in the red-line version of TOP-006 says: "Load patterns now covered in the new TOP-005. Remainder not required for reliability." Since TOP-005 is to be retired, we are unable to find a new TOP-005 that covers this requirement. Please explain the relevance of this note.
Response: TOP-006-1**:** There was a problem with the original posted material. You are correct; this is now covered under the data specification requirements of TOP-003-1.		

Organization	Yes or No	Question 10 Comment
SERC OC Standards Review Group	Yes	Although we agree with the retirements of TOP-005, 006, 007 and 008, the following discrepancies are noted: Top-006-1, R5 indicates this requirement has been removed to new TOP-005. TOP-005 is being eliminated and a new TOP-005 is not being developed. Where does this requirement reside? or is it really needed? TOP-008-0, R1 indicates this requirement has been moved to TOP-003-1, which is the standard for Operational Reliability Data. Should this read that it has been moved to TOP-004? Per-001-0, R1. We agree with the elimination of this Standard The authority of the system operator is mandated in FERC Order 693, paragraph 112.
Response: TOP-006-1**:** There was a problem with the original posted material. You are correct; this is now covered under the data specification requirements of TOP-003-1. TOP-008-0: There was a problem with the original posted material. As re-posted in the Implementation Plan, this should read: Deleted – now covered by TOP-001-2, R6 for IROL. Taking immediate steps for relief of all SOLs experienced or contributed to may not always be prudent, especially if other organizations are addressing the cause. In such cases, uncoordinated immediate actions may be counterproductive. Accordingly, requiring immediate action to relieve all SOLs was deleted in consideration of TOP-001-1 and TOP-004-3 requirements applied in combination. PER-001-0: Thank you for your response.		
Dominion - Electric Market Policy	No	We believe that the existing standards are more clear those contained in this draft. This draft seems to be trying to delineate TOP and BA standards/requirements from RC standards/requirements. In doing so, the draft loses the feeling of cohesiveness of the existing standards.
Response: The re-drafting effort is trying to delineate the RC vs. TOP/BA standards as was pointed out in the SAR for this project.		
Southern Company Transmission	No	Both TOP-001-1, R1, and PER-001-0, R1, were deleted. These standard requirements require operating personnel under the TOP and BA to have the responsibility and authority to implement real time actions to ensure the stable and reliable operation of the bulk electric system. Additionally, in paragraph 1330 of FERC Order 693, FERC approved PER-001-0 as mandatory and enforceable. Accordingly, FERC is clear in its intention that the operating personnel of the TOP and BA have authority to take action without any managerial approval being required. Also, in paragraph 1582 of the Order 693, FERC states R3 of Reliability Standard IRO-001-0 establishes the decision-making authority of the reliability coordinator, but not operating personnel of the TOP or BA. These facts stated above could be exposing a reliability gap if this standard is approved as written because the entities performing the TOP and BA functions must have the support of a NERC standard to be able to take immediate action without management approval or intervention. Reliability Standards Compliance programs are based on abiding by the NERC standards. By the TOP and BA not having clear decision-making authority from a NERC standard could lead to senior management of a company stepping in and requiring their approval before operating personnel are allowed to take action to alleviate problem. This could lead to jeopardizing

Organization	Yes or No	Question 10 Comment
		reliability. TOP-001-1, R2 has been deleted. It would seem logical that a requirement for the TOP to take immediate action to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc., would be worthy of being kept in the standard. If it is a duplication of an existing requirement, then please reference where the duplicate requirement is located.? Under TOP-001-2, R2 the phrase "including potential impacts caused by disconnections prior to switching" was added to the requirement. This addition seems to provide too much specificity and provides a very granular view for the requirement. It is best to remove this phrase and bring the requirement back to a higher level and end the sentence after "emergency conditions". It was noted that TOP-001-2, R3 replaces TOP-001-1, R6 and that the following component of the old R3 was deleted: "provided that the requesting entity has implemented its comparable emergency procedures". For an entity to render emergency assistance to another entity who has not implemented their own internal company emergency procedures prior to seeking help from others is not a wise decision. Deleting this phrase would create a burden on others providing the emergency assistance. Unless it can be shown there are other standard requirements already containing this required action, we recommend NOT removing this phrase." Removal of the BA from requirement (TOP-002-2, R1) to plan operations into the future is not appropriate. Although it is agreed that CPS and DCS are much of the real-time basis for reliable operation, due to the physical requirements to start or even change output of many units, it is absolutely necessary that the BA plan a near-term operating horizon of several hours so that DCS and Energy Emergencies can be avoided. Removing the requirement for the BA to plan because DCS covers everything would be like removing the requirement for TOP to plan and just rely on the fact that the TOP has to correct SOL's and IROL's under TOP-004-1, R1 without any planning. Also, without this requirement to plan, under what basis would the BA have to request the generator output planning information currently in TOP-002-2, R15 that the SDT says will become part of TOP-003-1 data specifications? The Generator Operator could say there is no need for the BA to plan beyond what is needed for DCS and CPS and thus claim such requests are not needed. By removing this requirement the SDT has removed any basis for doing near-term planning. Similarly to the comment above for R1, the BA has a need to plan for the items covered in TOP-002-2, R5. Such a requirement should be included in the new R1 of TOP-002-3.? TOP-002-2, R8 requires the need to plan to meet Interchange Schedules and ramps, and should be carried forward to TOP-002-3. Even though INT-006 requires the BA to consider ramping capability in approving/denying Arranged Interchange, generation dispatch and unit capability can change significantly after an Arranged Interchange is approved. The BA must consider (i.e. plan) near-term ramps in being able to meet an upcoming Interchange ramp. The result of not planning for a ramp that can no longer be met is a frequency deviation. The ability to ramp is not a parameter in the BAL-

Organization	Yes or No	Question 10 Comment
		001 and BAL-002 standards. ACE is the basis for BAL-001 and BAL-002 and ramping capability is only one contribution to ACE and thus those standards should not be used as a reason for removing this requirement. In addition, the CPS criteria of BAL-001 are not granular enough (CPS1 is 12 month rolling average and CPS2 is a calendar month number) to manage real-time issues that can cause reliability problems. In the new TOP-003-1 which addresses reliability data needs, R2 and R3 require distribution to entities that provide Facility status. Why is the term status used? Why would not the distribution be to any entity that is the source of data under the specification R1 and not limit it to a Facility status source? In the mapping table of the Implementation Plan, TOP-006-1 R5, R6 and R7 were deleted with a reason given by the SDT that the monitoring activities are covered in the certification process. It is unclear how a one time verification of the activity during certification translates into a requirement that the monitoring processes continue and more importantly that violations have a penalty. It is recommended that these requirements be retained (and perhaps others deleted added back as well). Under TOP-004-3, R2 states that Agreements between TOPs are required for switching of BES tie lines. It is felt that this type of detailed information would be contained in the Interconnection Agreements between the two parties. Only when there are not existing Agreements in place would this requirement be necessary. In those cases where it is necessary, it is recommended that "specify switching" be replaced with "specify the procedures for switching". Under TOP-003-1, R4, the Balancing Authority should be added along with the Transmission Operator as receiving data as specified in R1. Requirement 1 requires the TOP and BA to have documented specification for data, and R4 requires the responsible entities to provide this data only to the TOP. If the BA is required to have the documented specification for data support, then the responsible entities should be required to provide appropriate data not only to the TOP but to the BA as well.

Response: TOP-001-1, R1 & PER-001-0, R1: Standards are written to a functional entity, not to individuals. How an organization meets the standard is entirely up to them.

TOP-001-1, R2: In the opinion of the SDT, TOP-004-3, R1 covers this issue.

TOP-001-2, R2: The SDT agrees and the phrase has been deleted.

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions**.**

TOP-001-2, R3: The SDT believes that there may be an issue here and will provide a specific question in the next posting to see what the industry thinks.

TOP-002-2, R1, R5 & R15: The SDT believes that in order for a BA to comply with CPS and DCS that they must plan and therefore a separate requirement is not required and would actually represent double jeopardy. The BAL standards cover these issues.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 10 Comment</th></tr>
<tr><td colspan="3">TOP-002-2, R8: The SDT believes that your comment contains the answer to the question in that BAL covers ACE and ramping is part of ACE.

TOP-003-1, R2 & R3: The SDT feels that the suggested wording is really equivalent and therefore no change was made.

TOP-006-1, R5, R6, & R7: Performance to other requirements adequately covers the need to monitor and therefore no separate specific monitoring requirement is needed.

TOP-004-3, R2: The SDT is asking a question in the second posting regarding the possible deletion of this requirement.

TOP-003-1, R4: Due to your comments, the SDT has changed TOP-003-1 as shown below.

TOP-003-1, Purpose: To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.

TOP-003-1, R1: Each Transmission Operator and Balancing Authority shall have a documented specification for data required to fulfill their respective responsibilities per the NERC Functional Model. The specification shall include:

TOP-003-1, R4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies).

TOP-003-1, M4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall make available evidence that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies) in accordance with Requirement R4. The data is limited to that needed by the Transmission Operator to support Operational Planning Analyses and reliability assessments. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.</td></tr>
<tr><td>FirstEnergy</td><td>Yes</td><td>While we support the reduction in the overall number of standards, the deleted standards contained some requirements whose deletion we can not support. We have communicated these requirements and the issues surrounding them in the responses to other questions on this form including question 12 at the end of this form.</td></tr>
<tr><td colspan="3">Response: Please see the response to question 12.</td></tr>
<tr><td>Duke Energy</td><td>Yes</td><td>TOP-005-1 Requirement R2 has been deleted because it is not a reliability concern. Has this requirement been picked up in NERC Rules of Procedure or business practices?

TOP-006-1 Requirement R4 is being deleted, and the comment says that load patterns are covered under TOP-005. But TOP-005 is also being deleted - is it intended that load data will be covered by TOP-003 now?</td></tr>
<tr><td colspan="3">Response: TOP-005-1: The way that the standards have been re-written, data from the ISN is no longer being requested.

TOP-006-1: There was a problem with the original posted material. You are correct; this is now covered under the data specification requirements of TOP-003-1.</td></tr>
<tr><td>MRO NERC Standards</td><td>Yes</td><td></td></tr>
</table>

Organization	Yes or No	Question 10 Comment
Review Subcommittee		
ITC Transmission	Yes	
IRC Standards Review Committee	Yes	
Montenay Power Corp.	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
Ameren	Yes	
Oncor Electric Delivery	Yes	
AEP	Yes	
Northeast Utilities	Yes	
American Transmission Company	Yes	
Santee Cooper	Yes	
Entergy Services	Yes	
PJM Interconnection	Yes	
Bonneville Power Administration	Yes	
ISO-NE	Yes	

Organization	Yes or No	Question 10 Comment
Response: Thank you for your response.		

11. If you are aware of any regional variances or any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement that would be required as a result of these standards, please identify them here.

Summary Consideration:

No respondents cited any regulatory function, rule order, tariff, rate schedule. legislative requirement or agreement that would impact the revised standards.

Organization	Yes or No	Question 11 Comment
Dominion - Electric Market Policy	Yes	Typically, GO, GOP, PSE, LSE entities are prohibited from by federal and/or state Standards/Codes of Conduct from access to much of the information that would be required to perform any type of 'reliability assessment', determination of criticality or adverse impact. Only entities such as the RC, TO, TOP and perhaps BA have access to all the necessary information to make such determinations. For the GO, GOP, PSE, LSE entities, any such determination is really a business risk assessment, not a reliability assessment.
Response: The requirement is not for the GO, GOP, PSE, or LSE to perform a reliability assessment. The requirement is the aforementioned entities to supply operational data such as unit output, derates, total load, known interchange schedules, etc., in an agreed upon format and periodicity to the TOP who will perform the reliability assessment.		
MRO NERC Standards Review Subcommittee	Yes	
Response: Without a specific reference, the SDT is unable to respond to your comment.		
Bonneville Power Administration	Yes	WECC TOP-STD-007-0 would now need to link to TOP-004-3 (R1).
Response: That is an administrative matter for WECC and beyond the scope of the SDT.		
NPCC	No	
Santee Cooper	No	

Organization	Yes or No	Question 11 Comment
PJM Interconnection	No	
FirstEnergy		Not aware of any.
ITC Transmission	No	
IRC Standards Review Committee	No	
Manitoba Hydro	No	
Consumers Energy Company	No	
Ameren	No	
Oncor Electric Delivery	No	
Entergy Services	No	
Independent Electricity System Operator	No	
Duke Energy	No	
Northeast Utilities	No	
American Transmission Company	No	
ISO-NE	No	
Response: Thank you for your response.		

12. Are there any other issues that need to be addressed? Please be specific.

Summary Consideration:

In response to industry comments, the following were changed:

TOP-001-2, Purpose: To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

TOP-001-2, R3: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements.

TOP-001-2, R4: Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination.

TOP-001-2, M4: The Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among impacted reliability entities in accordance with Requirement R4 unless conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

TOP-001-2, Data Retention for R5: The Transmission Operator shall make available evidence for the current calendar year and one previous year that it has informed its Reliability Coordinator of actions being taken to return the System to within limits when an IROL or SOL has been exceeded in accordance with Requirement R5 and Measurement M5.

TOP-001-2, Data Retention for R6: The Transmission Operator shall make available evidence for the current calendar year and one previous calendar year of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv in accordance with Requirement R6 and Measurement M6.

TOP-001-2, R4 VSL	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with 25% or less of the affected reliability entities unless conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 25% or less than or equal to 50% of the affected reliability entities unless conditions	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 50% or less than or equal to 75% of the affected reliability entities unless conditions	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 75% of the affected entities unless conditions did not permit such coordination.

		did not permit such coordination.	did not permit such coordination.	

TOP-003-1, R4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies).

Organization	Yes or No	Question 12 Comment
Santee Cooper	Yes	TOP001-2 R2 the disconnections prior to switching portion of this requirement. Does this mean the RC and TOPs have to be called prior to switching in emergency situations? (e.g. a line is about to burn down) TOP004-3 R2 what is meant by Agreements in this context? An Agreement is a contract written or verbal. Do Interchange Agreements between TOPs fulfill this obligation? What is meant by synchronous BES tie line and should this be a defined term? Is this just to differentiate between AC and DC tie lines?
Response: TOP-001-2, R2**:** The SDT has changed the requirement to provide additional clarity as to intent. . **TOP-001-2, R2**: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions. TOP-004-3, R2**:** Agreement is a defined term in the NERC Glossary. The SDT will post a question in the next iteration on this topic.		
SERC OC Standards Review Group	Yes	We suggest eliminating R2 of TOP-004-3. An interconnection agreement between two entities will include this requirement.
Response: The SDT will ask a question on this topic in the next posting. .		
Dominion - Electric Market Policy	Yes	Generic comment - There appears to be a hieracy created by Reliability Standards with the RC being highest, followed by (equally?) the BA and TOP. If this is true, we'd prefer that the RC identify requirements necessary to enable it to meet its requirements under the standards. As new standards are being created, there appears to be the potential for some entities to have to provide the same information or have to coordinate actions with multiple entities but at different times, using different protocols. As examples:IRO-002-2 already requires the RC "to determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability

Organization	Yes or No	Question 12 Comment
		Coordinators." EOP-002-2 states "A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load." In order to meet this requirement, the BA will likely have to request GO/GOP to provided unit availability data (outages, derates) and the DP, TOP and/or LSE to provide load projections. This same information will likely be needed (and required) by the RC to perform its assessments. In this project TOP-001-008@ R4 states "Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to affect other reliability entities." and TOP-003-1@ R4 requires entities to provide data, as specified in Requirement R1, to its Transmission Operator(s). If these entities have provided the information required by their respective RC and the RC is required to coordinate with other RCs (IRO-014-1) there appears to be duplication which increases the workload of each entity and introduces opportunity for miscommunication or what may appear to conflicting submission of data (assuming that format and timeline differ). Specific commentsTOP-001-2 R3 - concern about ambiguity of phrase "to others", particularity from the GOP perspective. For reliability standards, the GOP should only be required to provide such assistance when so requested by its RC. Any other obligations should be included in the terms and conditions of its Interconnection Agreement with the TO or DP and, as such, is outside the scope of these standards. R4 - Concern about phrase "coordinate its respective operations known or expected to affect other reliability entities with those entities", particularly as it applies to GOP. GOP doesn't have access to data, nor the expertise, to make reliability assessments and may be precluded by Codes/Standards from coordinating with other entities. Suggest revising to require GOP to provide data as required by its RC to perform reliability assessments. Since GOP has to follow emergency directives issued by RC or TOP, there is nothing for the GOP to coordinate. If GOP actions or planned actions are deemed to have the potential to result in adverse impact to reliability, the RC or TOP should issue a directive to GOP to cancel such actions. TOP-002-3 - R3 should be deleted given that IRO-004@R3 states that "Each RC shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs." TOP-003R1.2 - Am concerned about the term "mutually agreeable format". Does the phrase 'mutually agreeable' apply to ALL applicable entities, or just the TOP and BA? Aren't there enough protocols and tools currently in existence (SDX, ICCP, RCIS) that the standard could at least address use of existing formats as opposed to 'mutually agreeable'? R4 - Does not require entities to provide data to BA although R1 requires BA to "?have a documented specification for data?.." and R3 requires each BA to "distribute its data specification to entities?". We suggest revising R4 to read "Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator and Balancing Authority." We removed the plural indicator as we believe that each entity's facility can be in only one TOP and BA area. If information relative to that facility is needed by multiple TOPs or BAs, those entities should share information. The entity should not be

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 12 Comment</th></tr>
<tr><td></td><td></td><td>required to submit data for the same facility to multiple reliability entities.</td></tr>
<tr><td colspan="3"> Response: Generic –The re-drafting effort is trying to delineate the RC vs. TOP/BA standards as was pointed out in the SAR for this project.
TOP-001-2, R3 - The SDT has reviewed this requirement and made changes to provide clarity. BA's have been removed to avoid duplication with EOP-001-0, Requirement R1 and the GOP is essentially under the control of the BA and therefore isn't needed here.
TOP-001-2, R3: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements.
TOP-001-2, R4 – The SDT believes that the industry needs to weigh in on this topic and will ask a specific question in the next posting.
TOP-002-3, R3 – The SDT disagrees and believes that it is important for the TOP to study its own system which may not be the same as what the RC studies as the objectives are different. No change made.
TOP-003-1, R1.2 –The SDT believes the term "mutually agreeable" gives leeway for the reliability entities to exchange the required data and doesn't preclude any protocols.
TOP-003-1, R4 – The SDT agrees with the inclusion of the BA and has changed Requirement R4 accordingly. The plurals are correct as multiple reporting requirements do exist and need to be accommodated in a national standard. If there is a single reporting requirement, then this wording remains intact and should not cause a problem.
TOP-003-1, R4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies). </td></tr>
<tr><td>Southern Company Transmission</td><td>Yes</td><td> In the purpose statement the term "functional entities" is used. The term creates a confusion of terms between the purpose statement and requirements. Requirements 4 and 7 call for coordination among "other reliability entities" and "reliability entities" respectively. Therefore, recommend replacing "functional" with "reliability".
The limits mentioned in TOP-001-2,R5 need more description. The recommended change is as follows: ?Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within the IROL limits when an IROL or SOL has been exceeded.?
Requirement 7 of TOP-001-2 is duplicative as it applies to the TOP to that of standard IRO-005-2, R13. Could this result in a double jeopardy for non compliance with this requirement?
In TOP-003-1, in the Purpose statement replace "system" with "System".
In R1 of TOP-003-1, it is recommended that the term "specification" throughout the standard be replaced with a better term to describe what is meant in the standard. For example, the word "catalog" may be a better term. Also, it recommended that in the sub-bullet R1.3 the word "providing" should be replaced with "exchanging" . </td></tr>
</table>

Organization	Yes or No	Question 12 Comment
		In TOP-001-2, In section 1.4 of Data Retention the term "reliability entities" is capitalized. Should it be in lower case? On several requirements (e.g., TOP-006-1, R1;TOP-008-1, R1) recommended for retirement, there is a comment in the redline version stating that the requirement is covered in another standard. Upon reviewing the other standard, the requirement was not found. Was the latest version of the standard posted properly on the NERC website?
Response: 1 – The SDT thanks you for your comment and will replace 'functional entity' with 'reliability entity'. **TOP-001-2, Purpose**: To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES). 2 – The SDT believes the as written requirement is correct as it includes SOL or IROL limits, as appropriate, with the current wording. 3 – Your reference is incorrect, the standard cited has been updated and the correct reference is IRO-005-3, Requirement R10. Having said that, you are correct in your premise and TOP-001-2, Requirement R7 has been deleted. 4 – "System" is a defined term, but in the context of the Purpose statement "Transmission System" is not a defined term and therefore should not be capitalized. 5 – The SDT believes specification is the correct word. "Catalog" as suggested or "list, file, register, etc." is limiting in nature. Using the word "specification" augments the sub-requirements. The SDT finds providing and exchanging in this context to be basically equivalent and no change was made. 6 – The SDT thanks you for your comment. 'Reliability entities' is not a defined term and therefore should be lower case. TOP-006-1**:** This is now covered under the data specification requirements of TOP-003-1. TOP-008-1: As re-posted in the Implementation Plan, this should read: "Deleted – now covered by TOP-001-2, R6 for IROL. Taking immediate steps for relief of all SOLs experienced or contributed to may not always be prudent, especially if other organizations are addressing the cause. In such cases, uncoordinated immediate actions may be counterproductive. Accordingly, requiring immediate action to relieve all SOLs was deleted in consideration of TOP-001-1 and TOP-004-3 requirements applied in combination."		
Bonneville Power Administration	Yes	Good Ideas - thanks. However, do not see anything analogous to the current TOP-001 R1. and think we should retain something of this nature.
Response: The SDT thanks you for your comment but believes Requirement R1 of TOP-001-1 is not measurable. Furthermore, as identified in the Implementation Plan, the SDT does not feel that this requirement is needed in a Reliability Standard. Other standards already require the necessary actions. If this statement was intended to protect the operator from liability, it doesn't provide any real protection.		
FirstEnergy	Yes	1. In TOP-001-2 R2, the term "disconnections" is ambiguous. In addition, as written this requires the RC be notified prior to operator action. While we agree that we do not want operators taking actions that sacrifice accuracy for speed, we do not support the concept of approving all mitigation actions prior to implementation. Nor do we believe this concept serves to preserve or enhance reliability in situations where time is of the essence. The motivations behind the original requirements were 1) to preserve the reliability of the interconnection through recognition and mitigation actions and 2) to

Organization	Yes or No	Question 12 Comment
		ensure that removal of overloaded transmission facilities was done only when it preserved or enhanced reliability. We feel these two concepts should be managed as individual requirements similar to the requirements in effect today. The Drafting Team should include the system conditions of overload, abnormal voltage, and reactive conditions, and endangered equipment as system conditions permissible for action then communication. 2. In TOP-001-2 R3, the Drafting Team dropped the concept of the requesting entity implementing its comparable emergency procedures prior to an entity being required to lend assistance. This could lead to a request and requirement for TOp A to shed load in its area when TOp B, the entity requesting the assistance, has not shed load that would mitigate the emergency in its own area. This requirement should be revised to state, "Each Transmission Operator, Balancing Authority, and Generator Operator shall render emergency assistance to others, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements and provided the requesting entity has implemented its comparable emergency procedures. " 3. In TOP-001-2 R4, the Drafting Team preserved limiting the delay in notifications to system conditions. This change as written does not provide additional clarity as to which system conditions require and do not require notification in advance of action. This seems to make this Requirement too vague to be measurable. As currently proposed, this requirement means someone must decide which system conditions require and do not require advance coordination. Additional rules need to be developed by the team concerning the system conditions that require notification in advance of action. While we agree that we do not want operators taking actions that sacrifice accuracy for speed, we do not support the concept of approving all mitigation actions prior to implementation. Nor do we believe such a concept serves to preserve or enhance reliability in situations where time is of the essence. We recommend the drafting team restore TOP-001-1 R7.3 that states, "When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, GOp notifies TOp, TOp notifies RC and adjacent TOps at earliest possible time." As currently written this proposed requirement leaves it open for the operator to complete the mitigation actions prior to notifications taking place when system conditions do not permit such coordination which is inconsistent with the Drafting Team's action on other requirements, but is appropriate considering the potential system conditions. 4. In TOP-001-2 R5, the Drafting Team is supporting action in advance of communication, we support this stance. 5. The Drafting Team proposes to delete TOP-007-0 R3 that states, "A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2" because the authority already exists and does not need to be cited in a requirement. Other than the Reliability Standards, where does this authority exist? It seems that the drafting team intends to remove all requirements that provide for this authority in the Reliability Standards. We cannot support this stance. Without this provision in the standards, there is nothing to preclude an organization from requiring its operators to obtain approval from superiors within the organization prior to taking an action such as load shed, redispatch, reconfiguration, etc. that they know will preserve or enhance the reliability of the BES. While we agree these requirements do not provide any legal protection to the operator, they do enhance reliability of the BES by ensuring authority to act remains in the hands of the operator at the controls of the

Organization	Yes or No	Question 12 Comment
		System. 6. The Drafting Team deleted TOP-002-2 R1 because they feel the BA only needs to respond to CPS and DCS. Does the BA only have responsibility for responding to CPS and DCS? How does the TOp meet its obligations without BA assistance? How about MVAR support? It is not realistic to require a TOp to issue a reliability directive to a BA, GOp, GO, DP, etc. each time it needs some assistance in preparing a plan for future system conditions. We request the Drafting Team reconsider the application of the "BA only needs to respond to CPS and DCS" concept and instead apply the measure of reliability of the BES as the litmus test for requirements. 7. The Drafting Team deleted TOP-002-2 R2 as a good utility practice that is not measurable. We support this change since the TPL standards will support the interface between operations and planning. 8. The Drafting Team deleted TOP-002-2 R3 as the LSE and GOP are governed by their Interconnection Operating Agreements. We are concerned with relying on agreements as a sole means of providing for BES Reliability. Reliability related behavior is best governed by reliability standards. Therefore, we request the drafting team reinstate R3 of TOP-002-2. 9. In TOP-002-3 R1 and R2 the drafting team dropped the BA plan from the requirement. How will the TOP obtain information and assistance needed from the BA necessary to plan to meet scheduled system configuration in light of the fact that the work plan for these standards does not include any revisions to the BAL standards to require that support? 10. The Drafting Team deleted TOP-002-2 R7. With this deletion, how will the BA's plan for energy reserves insure its deliverability without TOp assistance? The implementation plan does not include any revisions to the BAL standards to verify deliverability. This deletion seems to segment the planning activities too much to ensure reliability. 11. The Drafting Team deleted TOP-002-2 R8 and R10. With this deletion, how does the TOp meet its voltage and reactive obligations without BA assistance? The implementation plan does not include any revisions to the BAL standards and CPS and DCS do not cover reactive support. What's left in the standards to ensure reactive capacity is available on generating units to support voltage needs? 12. The Drafting Team deleted TOP-002-2 R18. This requirement should be retained and revised to state, "Neighboring BAs, TOps, TOs, use identical Tie- line names based on terminal end facility names when referring to transmission facilities. The purpose of this requirement is to ensure Company A and Company B are sure they are talking about the same Tie-line. 13. The Drafting Team deleted TOP-003-0 R1. This deletion eliminates the requirement for the GOp to provide outage data to the TOp. This requirement should be retained. 14. The Drafting Team has developed this standard based on the changes planned or proposed for other standards. This standard should not be finalized until all other standards that these changes are based on have been regulatory approved in order to avoid creating a reliability gap through deletion of an existing standard and the failed adoption of a proposed

Organization	Yes or No	Question 12 Comment
		standard. 15. TOP-004-3 R2 uses the term "Agreement" that is currently defined as "A contract or arrangement, either written or verbal and sometimes enforceable by law." Until the proposed revision to the definition of the term "Agreement" that would include "mutually agreed upon procedures and protocols" this requirement should be revised to state, "TOp has Agreements or mutually agreed upon procedures or protocols with directly interconnected TOps that specify switching of synchronous BES tie lines." 16. TOP-003-1 R1 be revised to state, "Each Transmission Operator, Balancing Authority, Generator Operator, Generator Owner, Transmission Owner, Purchasing-Selling Entity, Load Serving Entity, and Distribution Provider shall provide all data requested in writing by the Transmission Operator or Balancing Authority using the periodicity and in the format requested." With the adoption of this change, TOP-003-1 R2, R3, and R5 could be dropped because R1 covers all entities and data requirements. 17. In addition, with this change, the VRF for R1 should be changed to "High." The PSE should be added to the applicability of this requirement as they may have information that intermediary TOps need concerning large magnitude near-term sales and purchase power transfers that are unconfirmed with a high probability of implementation that should be studied by operations planners for potential impacts on the reliability of the BES. 18. The Drafting Team proposes to delete the TOP-006-1 R5, R6 and R7 as they are "covered by the certification process and no longer necessary." The certification program is being scaled back in part due to the reliability standards and the drafting team is removing requirements from the standards because the certification program covers it. We should not rely on programs outside of the reliability standards to provide for the reliability of the BES. These three requirements should be reinstated and revised to improve clarity and measurability.

Response: 1 – The SDT has modified TOP-001-2, Requirement R2 for clarity.

TOP-001-2, R2: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions.

2 – The SDT is going to ask a specific question in the next posting on this issue.

3 – The SDT believes the requirement as written addresses when coordination is required with the statement of “operations known or expected to affect other reliability entities”. The SDT also believes it would be nearly impossible to list every scenario concerning conditions. Furthermore, the SDT believes statements such as “at the earliest possible time” and “as soon as possible” are not measurable. No change made.

4 – Thanks for your comment.

5 – The SDT believes this is covered in EOP-001-0, Requirement R3.3.

6 – The SDT believes DCS and CPS criterion is only applicable to the BA function. Furthermore, the SDT does not fully understand the premise of your question and

Organization	Yes or No	Question 12 Comment
does not see the parallel between your concern and TOP-002-2, Requirement R1. 7 – Thanks for your comment. 8 – This is addressed in TOP-003-1, R4. 9 – This is addressed in TOP-003-1, R5. 10 – This is addressed in TOP-003-1, R5. 11 – The SDT believes that this is already covered by VAR-001. 12 – This is being addressed by Project 2007-02: Operations Communications protocols. . 13 – This is addressed in TOP-003-1, R4. 14 – This is addressed in the proposed Implementation Plan. Note that in some Canadian jurisdictions, a standard becomes enforceable once the BOT approves a standard, subject to any delays identified in the associated Implementation Plan. 15 – The SDT may be deleting this requirement. A specific question will be raised in the next posting on this topic. 16 – The SDT believes that the current wording provides the flexibility needed to fulfill this task. No change made. 17 – The SDT doesn't believe that a specification falls within the definition of High VRF. The SDT believes that PSE data would be commercial data and not reliability data and has not made this change. 18 – TOP-006-1, R5, R6, & R7: Performance to other requirements adequately covers the need to monitor and therefore no separate specific monitoring requirement is needed.		
MRO NERC Standards Review Subcommittee	Yes	In standard TOP-004-3 and in section "1.5 Additional Compliance Information", what if you don't meet this reporting process? What will happen?
Response: The SDT believes having a reason to miss the reporting process also means you violated Requirement R1 of the standard and a penalty would be assessed.		
ITC Transmission	Yes	1. TOP-001 R2 the phrase "disconnections prior to switching" needs to be clarified. Does this refer to individual facilities or complete disconnection from an interconnection? 2. TOP-001 R3 It would be helpful to have a definition of 'emergency', recognizing this is a broader issue than just this standard. 3. TOP-003 R1 It is unclear who is this data exchange requirement is applicable to. By reading on to R2 and R3, one can assume the intended audience, however the requirement should be written to clear as a standalone item.

Organization	Yes or No	Question 12 Comment
		4. TOP-004 R1 This requirement should be incorporated into TOP-001, as it logically flows from the requirements there. This would facilitate possible eliminate of TOP-004 altogether. 5. TOP-004 R2 The phrase "specify switching" is unclear. Believe this is an unnecessary requirement as TOP-001 R4 already requires the coordination of operations.
Response: 1 – The SDT has removed this phrase. **TOP-001-2, R2**: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions. 2 –The SDT will use the word "emergency" as it is consistent with EOP standards. 3 – The SDT believes reading the requirements as a whole provides the clarity you are seeking. 4 – The SDT will evaluate this idea after the industry responds to the question on elimination of Requirement R2. 5 – The SDT will ask a specific question about eliminating this requirement in the next posting.		
ISO-NE	Yes	We appreciate this as a first effort in reducing the redundancy in the V0 standards. There should be some clarity in the use of the term SOL in these standards. According to the NERC Glossary, SOLs include both IROLs and local facility limits. These standards use SOL in the context of only a local facility limit. The temporary exceedance of local facility limit (within the time limitations of the rating) should not be construed to be a violation in these standards. Failure to correct a local facility limit to the point where it leads to an IROL or damages equipment should be a violation. Records should only be maintained if the local limit is exceeded and not corrected within the allowable time of the limit. The record keeping required for non-violations in these standards is unnecessary.
IRC Standards Review Committee	Yes	We appreciate this as a first effort in reducing the redundancy in the V0 standards. There should be some clarity in the use of the term SOL in these standards. According to the NERC Glossary, SOLs include both IROLs and local facility limits. These standards use SOL in the context of only a local facility limit. The temporary exceedance of local facility limit (within the time limitations of the rating) should not be construed to be a violation in these standards. Failure to correct a local facility limit to the point where it leads to an IROL or damages equipment should be a violation. Records should only be maintained if the local limit is exceeded and not corrected within the allowable time of the limit. The record keeping required for non-violations in these standards is unnecessary.
Response: While you are technically correct on the use of the terminology, actual review of the requirements doesn't indicate any need to change any of the wording used in the proposed revisions.		

Organization	Yes or No	Question 12 Comment
The SDT agrees that record keeping for non-violations is unnecessary.		
Indiana Municipal Power Agency	Yes	TOP-003-1 Requirement 4. Entities are to provide data, as specified in R1, to their Transmission Operators. Does R1.2 (mutually agreeable format) cover the entities who are reporting data to their Transmission Operators? If the request for data is not done on a regular basis, the entities in R4 need to receive a proper request from the Transmission Operator and be given time to gather the data. Neither R1 or R4 clearly address this process and the standard should address how the entities in R4 will be made aware of any specification of data needed by the Transmission Operator or Balancing Authority.
Response: The SDT believes the standard as drafted covers who needs to provide required data, in what format, and the timeframe and periodicity.		
Ameren	Yes	Standard TOP-004-3, section "1.5 Additional Compliance Information" - should this be included in R1/M1? Why is there a separate section at the end?
Response: This statement is dictated by the Compliance Guidelines. Because there is no impact to reliability if the report is not filed, the action of filing the report does not meet the criteria for an enforceable reliability requirement. Note that in accordance with the Sanctions Guidelines, if an entity fails to file the report as identified, then the Compliance Enforcement Authority may determine that the failure to report justifies a larger penalty than would otherwise be assessed.		
Entergy System Planning & Operations (Gen & Mktg)	Yes	The Implementation Plan refers to items in other proposed standards that will take the place of existing requirements, some of which are referred to by project number and others by standard number. In either case, the proposed standard that will contain the requirement should be presented or easily referenced. for example the propose IRO standards that will accommodate requirements moved from the TOP standards are not available for review and confirmation. Also, several requirements were deleted because they were "immeasurable". Some of these items should be revisited and determined if an alternative "measurable" requirement can be drafted. For example, it is important that an entity not continue operate in an unknown operating state (TOP-004 R3) and promptly return to an analyzed conditions/or perform an analysis for the current condition.
Response: The referenced standards and projects are all readily available on the NERC web site. To have included them in the Implementation Plan would have created an extremely large and unmanageable document. The SDT did look at alternative measures in each case and where requirements were deleted, decided that there was no suitable alternative.		
Entergy Services	Yes	1. Please expound upon the reasons why the SDT determined that TOP-002-2 R19 and TOP-004-2 R4 are unmeasurable. 2. TOP-001-2 R4 is going to be very difficult to measure. Any guidance the SDT can provide on how to demonstrate

Organization	Yes or No	Question 12 Comment
		compliance would be appreciated. 3. TOP-002-3 R3: The requirement that was mapped to this in the implementation plan used the phrase "shall coordinate." We think that R3, as written, is too vague. Also, it is more command and control versus a collaborative effort as implied by the previous use of "coordinate."
Response: 1 –TOP-002-2, R19 is unmeasurable because 'accurate' is not a measurable term. TOP-004-2, R4 is unmeasurable because 'valid' is a vague term. 2 – The SDT believes the criteria are identified in the Measures. Beyond that, the SDT can't provide compliance guidance. 3 – The SDT believes the requirements as drafted provide an appropriate level of reliability and places the responsibility on the TOP where it belongs. No change made.		
Duke Energy	Yes	1. TOP-001-2 Requirement R4, Measure M4 and VSLs for R4 : What does the word "affect" mean? Any operation by a TO or GO could have a slight affect on other reliability entities. The word "affect" should be qualified in some manner, to avoid a requirement to coordinate operations with negligible impact. We suggest using the phrase "have a reliability impact upon" instead of the word "affect". 2. TOP-004-3 Requirement R2, Measure M2 : What does "specify switching" mean? We suggest this wording be removed from the requirement. This requirement may have been moved from TOP-004-1 Requirement R6, but it is unclear. 3. TOP-008-0 Requirement R1 is being deleted. The Comment says that this is now covered by TOP-003-1, and in consideration of TOP-001 and TOP-004 requirements in combination. We think the Comment should not reference TOP-003-1. 4. TOP-002-2 Requirement R11 contains a requirement for a seasonal assessments to determine SOLs. Where is this requirement in the revised standards?
Response: 1 – The SDT has incorporated your suggested language. **TOP-001-2, R4**: Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. **TOP-001-2, M4**: The Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among impacted reliability entities in accordance with Requirement R4 unless conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.		

TOP-001-2, R4 VSL	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not	The Transmission Operator or Generator Operator did not

Organization	Yes or No	Question 12 Comment

	coordinate their respective operations known or expected to impact other reliability entities with 25% or less of the affected reliability entities unless conditions did not permit such coordination.	coordinate their respective operations known or expected to impact other reliability entities with more than 25% or less than or equal to 50% of the affected reliability entities unless conditions did not permit such coordination.	coordinate their respective operations known or expected to impact other reliability entities with more than 50% or less than or equal to 75% of the affected reliability entities unless conditions did not permit such coordination.	coordinate their respective operations known or expected to impact other reliability entities with more than 75% of the affected entities unless conditions did not permit such coordination.

2 – The SDT will ask a specific question in the next posting about deleting this requirement.

3 – The SDT made this correction in the revised Implementation Plan that was posted during the first comment period.

4 – The SDT believes reliability has been improved by requiring an assessment for next day operations and that this is as far out as a requirement needs to cover. You can always do more that the requirements. Longer term studies are done in planning and complement these assessments.

Organization	Yes or No	Question 12 Comment
AEP	Yes	The intent of TOP-004-03 R2 requires some clarification. It seems unnecessary to have an agreement for switching every BES tieline. It seems unlikely that every conceivable situation for switching a tieline could be covered in any type of agreement.

Response: The SDT will ask a question in the next posting about deleting this requirement.

Organization	Yes or No	Question 12 Comment
American Transmission Company	Yes	1. TOP-001-2 Requirement 2: First Concern: NERC Definition for Emergency: "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System" ATC's believe that anticipating an abnormal system condition that could result in an Emergency would be very difficult to certify compliance. It's our position that the requirement should be limited to actual Real-Time Emergency conditions. If the SDT disagrees than we request information on how a company could certify compliance on its ability to anticipate an emergency. 2. Second Concern: Currently the requirement requires notification of an automatic or immediate manual action prior to the action for an Emergency. We believe that notification prior to switching may put the system and/or equipment at a greater level of risk. The requirement should contain language that states notification should be done "if time permits"

Organization	Yes or No	Question 12 Comment
		otherwise it should be done following the action. 3. TOP-001-2 Requirement 4:What is the minimum level of "affect" that requires communication? 4. TOP-002-3 Requirement 1: Would a single assessment of next day's operation satisfy this requirement? or, Is the requirement asking for multiple next day operations to account for load changes expected throughout the day?
Response: 1 – The SDT studied your suggestion but feels that the requirement is clear as written and that your suggestion could result in a reduction in the reliability of the system. To the degree that an entity anticipates an Emergency, that information should be shared and this is what the requirement says. 2 – The SDT has changed the requirement to address your concern. **TOP-001-2, R2**: Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions. 3 – The SDT will replace the word "affect" with "have a reliability impact upon". **TOP-001-2, R4**: Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. 4 – There is only one assessment required but an assessment may require multiple studies. It is up to the entity to determine how many studies they must perform in order to assess of their next day operations		
NPCC	No	
PJM Interconnection	No	
Montenay Power Corp.	No	
Manitoba Hydro	No	
Consumers Energy Company	No	
Oncor Electric Delivery	No	
Independent Electricity System Operator	No	

Organization	Yes or No	Question 12 Comment
Northeast Utilities	No	
Response: Thank you for your response.		

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The schedule shows completion of the project in 3Q09. The current draft is the second posting of the revised standards. As part of the proposed revisions, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	July 2009
2. Post for re-ballot.	September 2009
3. Submit to BOT.	September 2009
4. Submit to regulatory authorities for approval.	October 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Coordination of Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:**

   To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

   4.4. Distribution Providers

   4.5. Load-Serving Entities

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each reliability directive issued by the Transmission Operator, unless the respective entity informs the Transmission Operator that such actions would violate safety, equipment, regulatory or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R3. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R4. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R6. The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. The Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall each make available upon request, in accordance with Requirement R1, evidence that it either: (a) complied with each reliability directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. The Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions in accordance with Requirement R2. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M3. The Transmission Operator shall make available upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R3 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. The Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among impacted reliability entities in accordance with Requirement R4 unless conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M5. The Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M6. The Transmission Operator shall make available evidence of when it acted or directed others to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v in accordance with Requirement R6. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements.
R2	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions on one occasion.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions on two occasions.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions on three occasions.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of actual and anticipated Emergency conditions on four or more occasions.
R3	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, and such actions would not violate safety, equipment, regulatory, or statutory requirements.

	Lower	Moderate	High	Severe
R4	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with 25% or less of the affected reliability entities unless conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 25% or less than or equal to 50% of the affected reliability entities unless conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 50% or less than or equal to 75% of the affected reliability entities unless conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to impact other reliability entities with more than 75% of the affected entities unless conditions did not permit such coordination.
R5	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on one occasion.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on two occasions.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on three occasions.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on four or more occasions.
R6	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on one occasion.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on two occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on three occasions.	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v on four or more occasions.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

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2. Number: TOP-001-2

3. Purpose:

To ensure coordination between and among ~~functional~~reliability entities for the reliability of the Bulk Electric System (BES).

4. Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

4.4. Distribution Providers

4.5. Load-Serving Entities

5. Effective Date: All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each reliability directive~~s~~ issued by the Transmission Operator, unless the respective entity informs the Transmission Operator that such actions would violate safety, equipment, regulatory or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Transmission Operator shall inform its Reliability Coordinator and affected Transmission Operators of ~~Real-Time or~~ actual and anticipated Emergency conditions~~, including potential impacts caused by disconnections prior to switching~~. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R3. Each Transmission Operator~~, Balancing Authority, and Generator Operator~~ shall render emergency assistance to other~~s~~ Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R4. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected to ~~affect~~have a reliability impact on other reliability entities with those entities unless ~~System~~ conditions do not permit such coordination. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R6. The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

~~R7.Each Transmission Operator shall operate the Bulk Electric System to the most limiting parameter when there is a difference in derived operating limits amongst reliability entities. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*~~

C. Measures

M1. The Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall each make available upon request, in accordance with Requirement R1, evidence that it either: (a) complied with each reliability directive~~s~~ issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. The Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and affected Transmission Operators of ~~Real-Time or~~ actual and anticipated Emergency conditions~~, including potential impacts caused by disconnections prior to switching,~~ in accordance with Requirement R2. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M3. The Transmission Operator~~, Balancing Authority, and Generator Operator~~ shall ~~each~~ make available upon request, evidence that requested and available emergency assistance was rendered to other~~s~~ Transmission Operators in accordance with Requirement R3 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. The Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among ~~affected~~impacted reliability entities in accordance with Requirement R4 unless ~~System~~ conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M5. The Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M6. The Transmission Operator shall make available evidence of when it acted or directed others to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v in accordance with Requirement R6. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

~~M7.The Transmission Operator shall make available evidence such as dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts, of any occasion when it operated to a limiting parameter due to differing operating limits amongst reliability entities in accordance with Requirement R7.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance ~~as identified below~~ for each applicable Requirement and Measure for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- ~~The Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall each retain for the current calendar year and one previous calendar year, in accordance with Requirement R1 and Measurement M1, evidence that it either: (a) complied with reliability directives issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements.~~

- ~~The Transmission Operator shall retain evidence for the current calendar year and one previous calendar year that it has informed its Reliability Coordinator and affected Transmission Operators of Real-Time or anticipated Emergency conditions in accordance with Requirement R2 and Measurement M2.~~

- ~~The Transmission Operator, Balancing Authority, and Generator Operator shall retain evidence for the current calendar year and one previous calendar year that requested and available emergency assistance was rendered to others in accordance with Requirement R3 and Measurement M3 unless such actions would violate safety, equipment, regulatory, or statutory requirements.~~
- ~~The Transmission Operator and Generator Operator shall retain evidence for the current calendar year and one previous calendar year that operations known or expected to affect other Reliability Entities were coordinated among affected Reliability Entities in accordance with Requirement R4 and Measurement M4 unless System conditions do not permit such coordination.~~
- ~~The Transmission Operator shall make available evidence for three calendar years that it has informed its Reliability Coordinator of actions being taken to return the System to within limits when an IROL or SOL has been exceeded in accordance with Requirement R5 and Measurement M5.~~
- ~~The Transmission Operator shall make available evidence of when it acted, or directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v in accordance with Requirement R6 and Measurement M6.~~
- ~~The Transmission Operator shall retain evidence for the current calendar year and one previous calendar year of any occasion when it operated to a limiting parameter due to differing operating limits amongst reliability entities in accordance with Requirement R7 and Measurement M7.~~

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	~~The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements on one occasion.~~ N/A	~~The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements on two occasions.~~ N/A	~~The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with reliability directives issued by the Transmission Operator, unless the respective entity informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements on three occasions.~~ N/A	The Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator did not comply with a reliability directive~~s~~ issued by the Transmission Operator, ~~unless~~and the respective entity did not inform~~ed~~ the Transmission Operator that such action~~s~~ would violate safety, equipment, regulatory, or statutory requirements~~ on four or more occasions~~.
R2	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of ~~real-time or~~ actual and anticipated Emergency conditions on one occasion.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of ~~real-time or~~ actual and anticipated Emergency conditions on two occasions.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of ~~real-time or~~ actual and anticipated Emergency conditions on three occasions.	The Transmission Operator did not inform its Reliability Coordinator and affected Transmission Operators of ~~real-time or~~ actual and anticipated Emergency conditions on four or more occasions.
R3	N/A	N/A	N/A	The Transmission Operator~~, Balancing Authority, or Generator Operator~~ did not render emergency assistance to other~~s~~ Transmission Operators, as requested and available, ~~unless~~and such

	Lower	Moderate	High	Severe
				actions would not violate safety, equipment, regulatory, or statutory requirements.
R4	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to ~~affect~~impact other reliability entities with ~~one affected reliability entity or~~ 25% or less of the affected reliability entities unless ~~System~~ conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to ~~affect~~impact other reliability entities with ~~two affected reliability entities or~~ more than 25% or less than or equal to 50% of the affected reliability entities unless ~~System~~ conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to ~~affect~~impact other reliability entities with ~~three affected reliability entities or~~ more than 50% or less than or equal to 75% of the affected reliability entities unless ~~System~~ conditions did not permit such coordination.	The Transmission Operator or Generator Operator did not coordinate their respective operations known or expected to ~~affect~~impact other reliability entities with ~~four or more affected entities or~~ more than 75% of the affected entities unless ~~System~~ conditions did not permit such coordination.
R5	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on one occasion.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on two occasions.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on three occasions.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL or SOL has been exceeded on four or more occasions.
R6	The Transmission Operator did not make available evidence of its actions ~~the timing of when it acted,~~ or when it directed others to act, to mitigate the magnitude and	The Transmission Operator did not make available evidence of its actions ~~the timing of when it acted,~~ or when it directed others to act, to mitigate the magnitude and	The Transmission Operator did not make available evidence of its actions ~~the timing of when it acted,~~ or when it directed others to act, to mitigate the magnitude and	The Transmission Operator did not make available evidence of its actions ~~the timing of when it acted,~~ or when it directed others to act, to mitigate the magnitude and

	Lower	Moderate	High	Severe
	duration of exceeding an IROL within the IROL's T_v on one occasion.	duration of exceeding an IROL within the IROL's T_v on two occasions.	duration of exceeding an IROL within the IROL's T_v on three occasions.	duration of exceeding an IROL within the IROL's T_v on four or more occasions.
~~R7~~	~~The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on one occasion.~~	~~The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on two occasions.~~	~~The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on three occasions.~~	~~The Transmission Operator did not operate the BES to the most limiting parameter when there was a difference in derived operating limits amongst reliability entities on four or more occasions.~~

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

Standard Development Roadmap

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	July 2009
2. Post for re-ballot.	September 2009
3. Submit to BOT.	September 2009
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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that reliability entities have coordinated plans for meeting expected operating conditions.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

R3. The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

C. Measures

M1. The Transmission Operator shall have evidence that it has assessed next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

M2. The Transmission Operator shall have evidence that it has planned to preclude operating in excess of the IROLs identified as a result of the assessment performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL.

M3. The Transmission Operator shall make available evidence that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not perform an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and potential Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of any IROLs identified as a result of the assessment performed in Requirement R1.
R3	The Transmission Operator did not notify 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

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0	April 1, 2005	Effective Date	New
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Future Development Plan:

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~~**Simulated Contingencies** — The act of using planning and operating models to replicate Contingency responses that depict the net effect of design considerations~~

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that reliability entities have coordinated plans for meeting expected operating conditions.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and ~~Simulated~~potential Contingency events. *[Violation Risk Factor: ~~Low~~Medium] [Time Horizon: ~~Same-day~~ Operations Planning]*

R2. The Transmission Operator shall plan to preclude operating in excess of any Interconnection Reliability Operating Limits (IROLs) including those identified as a result of the assessment performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: ~~Same-day~~ Operations Planning]*

R3. The Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). *[Violation Risk Factor: High] [Time Horizon: ~~Same-day~~ Operations Planning]*

C. Measures

M1. The Transmission Operator shall have evidence that it has assessed next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated ~~operator logs or reports~~ power flow study results.

M2. The Transmission Operator shall have evidence that it has planned to preclude operating in excess of the IROLs identified as a result of the assessment performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL.

M3. The Transmission Operator shall make available evidence that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The Transmission Operator shall keep data or evidence to show compliance ~~as identified below~~ for each Requirement and Measure for a rolling six month period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- ~~The Transmission Operator shall retain evidence for a rolling six month period that it has assessed next day operations in accordance with Requirement R1 and Measurement M1.~~
- ~~The Transmission Operator shall retain evidence for a rolling six month period that it has planned to preclude operating in excess of any IROL identified as a result of the assessment performed in Requirement R1 in accordance with Requirement R2 and Measurement M2.~~
- ~~The Transmission Operator shall retain evidence for a rolling twelve- month period that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3 and Measurement M3.~~

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not perform an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and potential Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of any IROLs identified as a result of the assessment performed in Requirement R1.
R3	The Transmission Operator did not notify ~~one of the reliability entities or~~ 25% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify ~~two of the reliability entities or~~ more than 25% and less than or equal to 50% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify ~~three of the reliability entities or~~ more than 50% and less than or equal to 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify ~~four or more of the reliability entities or~~ more than 75% of the reliability entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

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Future Development Plan:

Anticipated Actions	Anticipated Date
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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-1

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Owners.

   4.4. Generator Operators.

   4.5. Interchange Authorities.

   4.6. Load-Serving Entities.

   4.7. Transmission Owners.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data required to fulfill their respective responsibilities per the NERC Functional Model. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R1.1. A list of required data to be exchanged including, but not limited to:

- Long term outages of Bulk Electric System equipment when they are known,
- Equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.

R1.2. A mutually agreeable format.

R1.3. A timeframe and periodicity for providing data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R1.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall make available evidence that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies) in accordance with Requirement R4. The data is limited to that needed by the Transmission Operator to support Operational Planning Analyses and reliability assessments. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for data in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall retain evidence for three calendar years that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies) in accordance with Requirement R4 and Measurement M4.
- Each Transmission Operator and Balancing Authority shall retain evidence for three calendar years that it has provided to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those entities necessary for reliability assessments and Real-Time operations in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator or Balancing Authority did not have one of the required elements of the documented specification for data.	The Transmission Operator or Balancing Authority did not have two of the required elements of the documented specification for data.	N/A	The Transmission Operator or Balancing Authority did not have a documented specification for data.
R2	The Transmission Operator did not distribute its data specification to 25% or less of the entities that has Facilities monitored by the Transmission Operator or to 25% or less of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 25% and less than or equal to50% of the entities that have Facilities monitored by the Transmission Operator or to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 50% and less than or equal to 75% of the entities that have Facilities monitored by the Transmission Operator or more than 50% and less than or equal to 75% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 75% of the entities that have Facilities monitored by the Transmission Operator or more than 75% of the entities that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to 25% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 25% and less than or equal to 50% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 50% and less than or equal to 75% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 75% of the entities that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, or Transmission Owner did not provide data and information, as specified in Requirement R1, to its Transmission Operator(s) or Balancing Authority(ies).

R5	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not provide to other Transmission Operators or Balancing Authorities with immediate responsibility for operational reliability, the data and information requested by those entities necessary for real-time monitoring and reliability assessments.

E. Regional Variances

None identified.

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-1

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to ~~plan and operate the Transmission system~~ fulfill their functional responsibilities.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Owners.

   4.4. Generator Operators.

   4.5. Interchange Authorities.

   4.6. Load-Serving Entities.

   4.7. Transmission Owners.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data ~~to support its Real-time monitoring and reliability assessments~~ required to fulfill their respective responsibilities per the NERC Functional Model. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R1.1. A list of required data to be exchanged including, but not limited to:

- Long term outages of Bulk Electric System equipment when they are known,
- Equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.

R1.2. A mutually agreeable format.

R1.3. A timeframe and periodicity for providing data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: ~~Low~~Medium]* *[Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data ~~to support its reliability assessments~~ in accordance with Requirement R1.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall make available evidence that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies) in accordance with Requirement R4. The data is limited to that needed by the Transmission Operator to support Operational Planning Analyses and reliability assessments. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for data ~~to support their reliability assessments~~ in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner shall retain evidence for ~~90~~ three calendar ~~days~~years that it has provided data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies) in accordance with Requirement R4 and Measurement M4.
- Each Transmission Operator and Balancing Authority shall retain evidence for ~~90~~three calendar ~~days~~years that it has provided to other Transmission Operators and Balancing Authorities with immediate responsibility for operational reliability, the data requested by those entities necessary for reliability assessments and Real-Time operations in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator or Balancing Authority did not have one of the required elements of the documented specification for data. ~~to support its real-time monitoring and reliability assessments.~~	The Transmission Operator or Balancing Authority did not have two of the required elements of the documented specification for data. ~~to support its real-time monitoring and reliability assessments.~~	N/A	The Transmission Operator or Balancing Authority did not have a documented specification for data. ~~and information to support its real-time monitoring and reliability assessments.~~
R2	The Transmission Operator did not distribute its data specification to ~~one entity or~~ 25% or less of the entities that has Facilities monitored by the Transmission Operator or to ~~one entity or~~ 25% or less of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to ~~two entities or~~ more than 25% and less than or equal to50% of the entities that have Facilities monitored by the Transmission Operator or to ~~two entities or~~ more than 25% and less than or equal to 50% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to ~~three entities or~~ more than 50% and less than or equal to 75% of the entities that have Facilities monitored by the Transmission Operator or ~~to three entities or~~ more than 50% and less than or equal to 75% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to ~~four or more entities or~~ more than 75% of the entities that have Facilities monitored by the Transmission Operator or ~~to four or more entities or~~ more than 75% of the entities that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to ~~one entity or~~ 25% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to ~~two entities or~~ more than 25% and less than or equal to 50% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to ~~three entities or~~ more than 50% and less than or equal to 75% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to ~~four or more entities or~~ more than 75% of the entities that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, or Transmission Owner did not

				provide data and information, as specified in Requirement R1, to its Transmission Operator(s) or Balancing Authority(ies).
R5	N/A	N/A	N/A	The Transmission Operator or Balancing Authority did not provide to other Transmission Operators or Balancing Authorities with immediate responsibility for operational reliability, the data and information requested by those entities necessary for real-time monitoring and reliability assessments.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
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5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The schedule shows completion of the project in 3Q09. The current draft is the second posting of the revised standards. As part of the proposed revisions, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	July 2009
2. Post for re-ballot.	September 2009
3. Submit to BOT.	September 2009
4. Submit to governmental authorities.	October 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Real-time Transmission Operations**
2. **Number:** TOP-004-3
3. **Purpose:** To ensure that Transmission Operators act to preserve the reliability of the Bulk Electric System in Real-time.
4. **Applicability:**

   4.1. Transmission Operators.
5. **Proposed Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R2. Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an identified Interconnection Reliability Operating Limit (IROL) and its associated IROL T_v as specified in Requirement R1. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion outside of the identified IROL and applicable IROL T_v.

M2. Each Transmission Operator shall make available evidence that it has Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2. Such evidence could include but is not limited to a dated document with confirmation of the Agreement, such as a signature page or a memorandum of understanding, in electronic or hard copy format.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Exception Reporting of any occasion in which it has operated outside an identified IROL and the applicable IROL T_v as specified in Requirement R1 and Measurement M1.

1.4. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v as specified in Requirement R1 and Measurement M1.
- The Transmission Operator shall retain evidence that it has current in force Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2 and Measurement M2 as well as any Agreements in force since the last compliance audit.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

Submit exception reports of each instance of exceeding an IROL for time greater than the associated IROL T_v to the Compliance Enforcement Authority within thirty calendar days of the event.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not operate within an identified Interconnection Reliability Operating Limit (IROL) and the associated IROL T_v for any single occasion.
R2	The Transmission Operator does not have Agreements with one of its directly interconnected Transmission Operators or 25% or less of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	The Transmission Operator does not have Agreements with two of its directly interconnected Transmission Operators or more than 25% and less than or equal to 50% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	The Transmission Operator does not have Agreements with three of its directly interconnected Transmission Operators or more than 50% and less than or equal to 75% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	The Transmission Operator does not have Agreements with four or more of its directly interconnected Transmission Operators or more than 75% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata
3	TBD	Changes pursuant to Project 2007-03	Revised

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A. Introduction

1. **Title:** **Real-time Transmission Operations**

2. **Number:** TOP-004-3

3. **Purpose:** To ensure that Transmission Operators act to preserve the reliability of the Bulk Electric System in Real-time.

4. **Applicability:**

   4.1. Transmission Operators.

5. **Proposed Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit~~s~~ (IROL~~s~~) and its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R2. Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an identified Interconnection Reliability Operating Limit~~s~~ (IROL~~s~~) and ~~their~~ its associated IROL T_v as specified in Requirement R1. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion outside of the identified IROL and applicable IROL T_v.

M2. Each Transmission Operator shall make available evidence that it has Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2. Such evidence could include but is not limited to a dated document with confirmation of the Agreement, such as a signature page or a memorandum of understanding, ~~of the Agreement~~ in electronic or hard copy format.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Enforcement Authority

   Regional Entity

   1.2. Compliance Monitoring and Reset Time Frame

   Not applicable

   1.3. Compliance Monitoring and Enforcement Processes

   Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

Exception Reporting of any occasion in which it has operated outside an identified IROL and the applicable IROL T_v as specified in Requirement R1 and Measurement M1.

1.4. Data Retention

The Transmission Operator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v as specified in Requirement R1 and Measurement M1.
- The Transmission Operator shall retain evidence that it has current in force Agreements with directly interconnected Transmission Operators that specify switching of synchronous BES tie lines in accordance with Requirement R2 and Measurement M2 as well as any Agreements in force since the last compliance audit.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

Submit exception reports of each instance of exceeding an IROL for time greater than the associated IROL T_v to the Compliance Enforcement Authority within thirty calendar days of the event.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not operate within an identified Interconnection Reliability Operating Limit~~s~~ (IROL) and the associated IROL T_v for any single occasion.
R2	The Transmission Operator does not have Agreements with one of its directly interconnected Transmission Operators or 25% or less of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	The Transmission Operator does not have Agreements with two of its directly interconnected Transmission Operators or more than 25% and less than or equal to 50% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	The Transmission Operator does not have Agreements with three of its directly interconnected Transmission Operators or more than 50% and less than or equal to 75% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.	The Transmission Operator does not have Agreements with four or more of its directly interconnected Transmission Operators or more than 75% of its directly interconnected Transmission Operators that address switching of synchronous BES tie lines.

E. Regional Variances

None identified.

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There are no new or revised definitions proposed in this standard revision.

Introduction

1. **Title:** ~~**Response to Transmission Limit Violations**~~

2. **Number:** ~~TOP-008-1~~

3. **Purpose:** ~~To ensure Transmission Operators take actions to mitigate SOL and IROL violations.~~

4. **Applicability**

   4.1. ~~Transmission Operators.~~

5. **Effective Date:** ~~January 1, 2007~~ All requirements will be retired on the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements are retired twenty-four months following Board of Trustees adoption.

A. Requirements

R1. ~~The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.~~

R2. ~~Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.~~

R3. ~~The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.~~

R4. ~~The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation~~.

B. Measures

M1. ~~The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)~~

M2. ~~The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1~~

M3. ~~The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)~~

M4. ~~The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents, copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)~~

M5. ~~The Transmission Operator that violates an SOL shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)~~

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

~~Regional Reliability Organizations shall be responsible for compliance monitoring.~~

1.2. Compliance Monitoring and Reset Time Frame

~~One or more of the following methods will be used to assess compliance:~~

~~- Self-certification (Conducted annually with submission according to schedule.)~~

~~- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~

~~- Periodic Audit (Conducted once every three years according to schedule.)~~

~~- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

1.3. Data Retention

~~Each Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.~~

~~Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.~~

~~If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.~~

~~Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,~~

~~The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance data~~

1.4. Additional Compliance Information

~~None.~~

2. Levels of Non-Compliance for Transmission Operator

2.1. Level 1~~: Not applicable.~~

2.2. Level 2: ~~Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.~~

2.3. Level 3: ~~Not applicable.~~

2.4. Level 4: ~~There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~2.4.1Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.~~

~~2.4.2Did not disconnect an overloaded facility as specified in R3.~~

~~2.4.3Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)~~

2.4.1 ~~Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)~~

D. Regional Differences

~~None identified.~~

Version History

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0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
1	TBD	Retire	Changes pursuant to

			Project 2007-03

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form for Second Draft of Standards for Real-Time Operations (Project 2007-03)

Please use the electronic comment form located at the link below to submit comments on the second draft of the standards for Real-Time Operations (Project 2007-03). Comments must be submitted by **May 7, 2009**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Background Information:

In the second posting for Project 2007-03, the Real-Time Operations Standard Drafting Team (RTO SDT) has attempted to clarify the proposed changes to the TOP family of standards based on industry comments received from the first posting. In doing so, several questions arose for which the RTO SDT is seeking industry guidance.

The RTO SDT is seeking comments on its second drafts of the following proposed standards:

- TOP-001-2 — Reliability Responsibilities and Authorities
- TOP-002-3 — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-3 — Transmission Operations
- TOP-008-1 — Response to Transmission Violations

1. TOP-001-2, R3: Regarding the requirement to provide emergency assistance - The SDT deleted the phrase “provided that the requesting entity has implemented its comparable emergency procedures” from the first iteration of the revised standard. Based on comments received from the first posting, the SDT is considering reinstating this phrase. Do you agree that this phrase should be reinstated?

   ☐ Yes

   ☐ No

   Comments:

2. TOP-001-2, R4: Regarding the requirement to coordinate operations – Based on comments received from the first posting, the SDT is considering deleting the GOP from this requirement. Comments were received questioning the role of the GOP in reliability analysis beyond providing the data in TOP-003-1, Requirement R4. Do you agree that the GOP should be deleted from this requirement?

   ☐ Yes

   ☐ No

   Comments:

3. TOP-001-2, R5: Regarding SOL exceedance notification – The consensus of the industry in the first posting was that some subset of SOLs needs to be reported but there was no clear cut agreement on what subset to report to the RC. The subset of SOLs to be reported must be easily identifiable and measurable while supporting reliability. Please remember in your response that as per the NERC Glossary that IROLs are a subset of SOLs. Given that requirement, what subset of SOLs do you feel need to be reported?

   ☐ Yes

   ☐ No

   Comments:

4. TOP-004-3, R2: Regarding Agreements on switching – Based on comments received from the first posting, the SDT is considering deleting this requirement. TOP-001-3, Requirement R4 already requires coordination of operations. Given that requirement, is TOP-004-3, Requirement R2 still necessary? Do you agree that TOP-004-3, Requirement R2 can be deleted?

   ☐ Yes

   ☐ No

   Comments:

5. The RTO SDT is attempting to respond to a directive in FERC Order 693 where a specific country-wide advance notice time period for planned outage notification would be established. Prior to writing such a requirement, the RTO SDT is polling the industry to see if it is needed and what the time period would be. Please indicate if you agree with such a provision. If you agree then please provide a number of days that you would consider appropriate for such advance notice, e.g., 7 days. If you disagree, then please state specific reasons for your disagreement.

☐ Yes

☐ No

Comments (including # of days if appropriate):

6. Do you generally support the revised standards? If your response is ‘No’, please explain your single biggest concern with the revised standards, including which specific requirement or set of requirements causes you the most concern and why.

☐ Yes

☐ No

Comments:

Implementation Plan for Project 2007-03: Real-Time Operations

Prerequisite Approvals

Changes made in this project to TOP-005-1, R1; TOP-007-0, R4 are dependent on corresponding changes being approved in Project 2006-06, Reliability Coordination:

- COM-001-1: Telecommunications
- COM-002-2: Communications and Coordination
- IRO-001-1: Reliability Coordination – Responsibilities and Authorities
- IRO-002-1: Reliability Coordination – Facilities
- IRO-014-1: Procedures to Support Coordination between Reliability Coordinators
- IRO-015-1: Notifications and Information Exchange between Reliability Coordinators
- IRO-016-1: Coordination of Real-Time Activities between Reliability Coordinators
- PER-004-1: Reliability Coordination – Staffing
- PRC-001-1: System Protection Coordination

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

Compliance with Standard

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DSP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							
TOP-001-2: Coordination of Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X		X
TOP-004-2: Real-Time Transmission Operations	X							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-1: Response to Transmission Limit Violations	Retired							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

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The assumption used by the SDT in establishing this Implementation Plan is that the project mentioned in the prerequisites: Project 2006-06, Reliability Coordination; has been approved prior to the implementation of this Project 2007-03, Real-Time Operations.

Effective Date of Revised Standards
All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

Retirement Date for Existing Standards
All requirements will be retired twenty-four months following the first day of the first quarter following regulatory approval.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan for Project 2007-03: Real-Time Operations

Prerequisite Approvals

~~Changes made in this project to TOP-001-2, R3; TOP-002-3, R16, R17; TOP-005-1, R1; TOP-006-1, R1 are dependent on corresponding changes being approved in Project Pre-2006, Operate within Interconnection Reliability Operating Limits:~~

- ~~IRO-008-1: Reliability Coordinator Operational Analyses and Real-Time Assessments~~
- ~~IRO-009-1: Reliability Coordinator Actions to Operate Within IROLs~~
- ~~IRO-010-1: Reliability Coordinator Data Specification and Collection~~

Changes made in this project to TOP-005-1, R1; TOP-007-0, R4 are dependent on corresponding changes being approved in Project 2006-06, Reliability Coordination:

- COM-001-1: Telecommunications
- COM-002-2: Communications and Coordination
- IRO-001-1: Reliability Coordination – Responsibilities and Authorities
- IRO-002-1: Reliability Coordination – Facilities
- IRO-014-1: Procedures to Support Coordination between Reliability Coordinators
- IRO-015-1: Notifications and Information Exchange between Reliability Coordinators
- IRO-016-1: Coordination of Real-Time Activities between Reliability Coordinators
- PER-004-1: Reliability Coordination – Staffing
- PRC-001-1: System Protection Coordination

~~Changes made in this project to TOP-002-3, R12 are dependent on corresponding changes being approved in Project 2006-07, ATC/TTC/AFC and CBM/TRM Revisions:~~

- ~~MOD-001-1: Available Transmission System Capability~~
- ~~MOD-008-1: TRM Calculation Methodology~~
- ~~MOD-028-1: Area Interchange Methodology~~
- ~~MOD-029-1: Rated System Path Methodology~~
- ~~MOD-030-1: Flowgate Methodology~~

Revision to Sections of Approved Standards and Definitions

There ~~is one~~ are no new definitions in the proposed set of standards.

~~**Simulated Contingencies** – The act of using planning and operating models to replicate Contingency responses that depict the net effect of design considerations.~~

~~A mapping table showing the disposition of existing requirements in the affected standards is shown below.~~

~~Existing Requirement~~	~~New Location~~
~~TOP-001-2 (redline version)~~	
~~R1~~	~~Deleted – The SDT does not feel that this~~

	~~requirement is needed in a reliability standard. Other standards already require the necessary actions. If this statement was intended to protect the operator from liability, it doesn't provide any real protection.~~
~~R2~~	~~Deleted – The SDT feels that dictating 'immediate action' could be detrimental to reliability.~~
~~R3 (re-formatted to R1)~~	~~All references to the RC and RC responsibilities have been removed from TOP standards as they are now covered in the revisions being undertaken in Project 2006-06. .~~
~~R4~~	~~The DP & LSE have been moved into the new R1 in the revised standard.~~
~~R5 (re-formatted to R2)~~	~~The added phrasing was adapted from TOP-008-0, R3. Deletions were made due to redundancies with TOP-004-3, R1.~~
~~R6 (re-formatted to R3)~~	~~Retained with changes.~~
~~R7 (re-formatted to R4)~~	~~Retained and expanded to incorporate sub-requirements.~~
~~R7.1 – R7.3~~	~~The sub-requirements have been moved into the main requirement in the revised standard.~~
~~R8~~	~~The first sentence has been deleted due to redundancies with CPS, DCS, and VAR standards. The requirement for real power in the second sentence was deleted as redundant with EOP-002-2, R1 & R6. The requirement in the second sentence for reactive power was deleted since you can't supply emergency reactive assistance remotely.~~
~~new R5~~	~~This requirement was moved here from TOP-007-0, R1.~~
~~new R6~~	~~This requirement was moved here from TOP-007-0, R2.~~
~~new R7~~	~~This requirement was moved from TOP-008, R2.~~
~~TOP-002-3 (redline version)~~	
~~R1~~	~~Deleted as BA only needs to respond to CPS and DCS and thus was not applicable. TOP now covered in new R1 below.~~
~~R2~~	~~Deleted as good utility practice but unmeasurable.~~
~~R3~~	~~LSE and GOP are governed by their Interconnection Operating Agreements and therefore not necessary here. TSP deleted~~

	~~as not applicable. TOP covered in new R3.~~
~~R4~~	~~Deleted as duplicative of proposed IRO-001-2, R1.~~
~~R5~~	~~Replaced by new R1.~~
~~R6~~	~~BA deleted as covered in BAL-002-0, R4. TOP covered in new R1.~~
~~R7~~	~~Deleted as duplicative of BAL-002-0, R1.~~
~~R8~~	~~Delete as not applicable to BA.~~
~~R9~~	~~Delete as duplicated in BAL-001 and BAL-002.~~
~~R10~~	~~Delete as not applicable to BA. TOP covered in new R2.~~
~~R11~~	~~First sentence covered in new R1. Second sentence deleted as this is now covered in proposed IRO-009-1 as well as FAC-010-1, FAC-011-1, and FAC-014-1. Third sentence covered in new R3.~~
~~R12~~	~~Deleted as now covered in MOD standards as part of Project 2006-07.~~
~~R13~~	~~Deleted as verification upon request not seen as needed by this standard. Passed on to Generator Verification team. Data now part of revised TOP-003-1 data specification requirements.~~
~~R14~~	~~Data now part of revised TOP-003-1 data specification requirements.~~
~~R15~~	~~Deleted as duplicative of IRO-010-1, R3. Data now part of revised TOP-003-1 data specification requirements.~~
~~R16~~	~~Data now part of revised TOP-003-1 data specification requirements.~~
~~R17~~	~~Deleted as duplicative of IRO-010-1, R3.~~
~~R18~~	~~Deleted as the SDT feels that this is a 'how' as opposed to a 'what'.~~
~~R19~~	~~Deleted as unmeasurable.~~
~~new R1, R2, & R3~~	~~New.~~
~~TOP-003-1 (redline version)~~	
~~R1~~	~~This requirement is now covered in the re-worded requirements below for the data specification.~~
~~R2~~	~~Deleted as now covered in IRO-001-2, R1 (proposed).~~
~~R3~~	~~Deleted as now covered in.IRO-001-2, R1 (proposed).~~
~~R4~~	~~Deleted as now covered in Project 2006-06.~~
~~R1 through R5 (re-formatted)~~	~~New data specification requirements.~~
~~TOP-004-3 (redline version)~~	
~~R1~~	~~Retained with changes.~~

~~R2~~	~~This is now covered by R1 with the inclusion of IROL and IROL T_v.~~
~~R3~~	~~This is now covered by R1 with the inclusion of IROL and IROL T_v.~~
~~R4~~	~~Deleted as unmeasurable.~~
~~R5~~	~~The first sentence was deleted as unmeasurable. The second sentence was deleted as it is covered by TOP-001-1, R1 & R4.~~
~~R6~~	~~The first sentence was deleted as it is good utility practice. The second sentence was deleted as all of the sub-requirements were deleted:~~ ~~R6.1 as duplicative of FAC-008 & FAC-009;~~ ~~R6.2 as duplicative of VAR-001-1, R1 for voltage levels and reactive power and real power by R10;~~ ~~R6.3 as it is now covered in new R2;~~ ~~R6.4 as now covered in TOP-002-3, R2.~~
~~new R2 (re-formatted)~~	~~Rewording of previous requirement.~~
~~TOP-005-1 (redline version)~~	
~~R1~~	~~Deleted – covered by IRO-010-1, R3.~~
~~R1.1~~	~~Deleted – covered in IRO-010.~~
~~R2~~	~~Deleted – The SDT did not feel that this was a legitimate reliability concern.~~
~~R3~~	~~Deleted – now covered as part of the new data specification requirements in TOP-003-1.~~
~~R4~~	~~Deleted – the PSE does not have any unique information needed by the TOP or BA.~~
~~TOP-006-1 (redline version)~~	
~~R1~~	~~Delete – now covered as part of the new data specification requirements in TOP-003-1.~~
~~R1.1~~	~~Delete – now covered as part of the new data specification requirements in TOP-003-1.~~
~~R1.2~~	~~Delete – now covered in IRO-010-1, R3.~~
~~R2~~	~~Delete – now covered as part of the new data specification requirements in TOP-003-1..~~
~~R3~~	~~Delete – now covered in PRC-001-1, R1.~~
~~R4~~	~~Deleted – now covered as part of the new data specification requirements in TOP-003-1.~~
~~R5~~	~~Delete – covered in certification process~~

	~~and no longer required in standards.~~
~~R6~~	~~Delete – covered in certification process and no longer required in standards.~~
~~R7~~	~~Delete – RC handled in IRO standards. TOP & BA now covered in certification process and no longer required in standards.~~
~~TOP-007-0 (redline version)~~	
~~R1~~	~~Moved to TOP-001-2, R5 (redlined version).~~
~~R2~~	~~Moved to TOP-001-2, R6 (redlined version).~~
~~R3~~	~~This authority already exists and does not need to be cited in a requirement. .~~
~~R4~~	~~Delete as this is now covered in the IROL Project.~~
~~TOP-008-0 (redline version)~~	
~~R1~~	~~Deleted – now covered by TOP-001-2, R6 for IROL. Taking immediate steps for relief of all SOLs experienced or contributed to may not always be prudent, especially if other organizations are addressing the cause. In such cases, uncoordinated immediate actions may be counterproductive. Accordingly, requiring immediate action to relieve all SOLs was deleted in consideration of TOP-001-1 and TOP-004-3 requirements applied in combination.~~
~~R2~~	~~First sentence replaced by TOP-004-3, R1. Second sentence moved to TOP-001-2, R7 (redlined versions).~~
~~R3~~	~~Delete first sentence – bad operating practice, actually eliminates operator flexibility and thus increases risk to the System. Delete second sentence as duplicative of IRO-009-1 as well as FAC-010-1, FAC-011-1, and FAC-014-1. Some phrasing moved to TOP-001-2, R2.~~
~~R4~~	~~Delete – now covered as part of the new data specification requirements in TOP-003-1.~~
~~PER-001-0 (redline version)~~	
~~R1~~	~~Deleted – This statement is not needed in a reliability standard. The standards already require the necessary actions.~~

Compliance with Standard

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DSP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							
TOP-001-2: Coordination of Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X		X
TOP-004-2: Real-Time Transmission Operations	X							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-~~0~~1: Response to Transmission Limit Violations	Retired							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

The assumption used by the SDT in establishing this Implementation Plan is that the project~~s~~ mentioned in the prerequisites: ~~Pre-2006, Operate within Interconnection Reliability Operating Limits;~~ Project 2006-06, Reliability Coordination; ~~and Project 2006-07, ATC/TTC/AFC and CBM/TRM Revisions have~~ has been approved prior to the implementation of this Project 2007-03, Real-Time Operations.

Effective Date of Revised Standards
All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

Retirement Date for Existing Standards
All requirements will be retired twenty-four months following the first day of the first quarter following regulatory approval.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
April 7–May 7, 2009

Now available at: http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Project Name:
2007-03 — Real-time Operations Standards

Due Date and Submittal Information:
The comment period is open **until 8 p.m. EDT on May 7, 2009**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Content for Comment Period:
The Real-time Operations Standards Drafting Team is seeking comments on its second drafts of the following proposed standards:

- TOP-001-2 — Reliability Responsibilities and Authorities
- TOP-002-3 — Normal Operations Planning
- TOP-003-1 — Planned Outage Coordination
- TOP-004-3 — Transmission Operations
- TOP-008-1 — Response to Transmission Violations

The drafting team revised purpose statements, requirements, measures, data retention, and VSLs. In addition, two bullets were added to TOP-003-1, Requirement R1.1 to address directives in FERC Order 693. The team deleted the definition of "Simulated Contingencies," as stakeholders indicated the definition is not needed.

Other Materials Posted:

- A revised implementation plan
- The drafting team's consideration of industry comments received during the first comment period

Project Background:
The drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. In addition, the drafting team has

supplied a complete set of Violation Risk Factors, Time Horizons, Measures, and Compliance elements including Violation Severity Levels. An Implementation Plan has been provided to show the timeframe for compliance.

Applicability of Standards in Project:

- Transmission Operator
- Transmission Owner
- Balancing Authority
- Generator Owner
- Generator Operator
- Interchange Authority
- Load-Serving Entity
- Distribution Provider

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (37 Responses)
Name (22 Responses)
Organization (22 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Question 1 (32 Responses)
Question 1 Comments (37 Responses)
Question 2 (34 Responses)
Question 2 Comments (37 Responses)
Question 3 (21 Responses)
Question 3 Comments (37 Responses)
Question 4 (31 Responses)
Question 4 Comments (37 Responses)
Question 5 (29 Responses)
Question 5 Comments (37 Responses)
Question 6 (33 Responses)
Question 6 Comments (37 Responses)

-
Individual
Scott McGough
Oglethorpe Power Corporation
No
Yes
Group
Bonneville Power Administration
Denise Koehn
Yes
Yes
No preference, we report identified WECC rated paths.
Yes
Yes
No preference.
Yes
Some suggestions: TOP-002-3 1) R1. Remove "and potential Contingency events". Any event could temporarily increase flows over the SOL (or IROL) or cause the SOL to decrease until the flows are mitigated per ROP-001. The system studies set the SOL's to protect the system for such events. The mitigation is then required in TOP-001-2 then (and TOP-004 if it is kept). 2) R1. Reword R1 similar to that of R2 in that TOP "plans" to preclude operating in excess of any SOLs for anticipated normal conditions. This is normal operational planning. All entities should not be planning to exceed SOL for normal conditions. Rewording: R1. "The Transmission Operator shall plan next day's operation to preclude operating in excess of any System Operating Limits (SOLs) during anticipated normal conditions."
Group
Project 2007-02 Operating Personnel Comm Protocols SDT
Harry Tom

Yes
The Operating Personnel Communication Protocols standard drafting team respectfully requests that the Real Time Operations team incorporate the following into your proposed TOP-001: "Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have procedures for the communication of information concerning the transmission emergency alerts in accordance with the conditions described in Attachment 1 Transmission Emergency Alerts ." In addition, the Applicability Section 4 would need to include Reliability Coordinators. The Operating Personnel Communications Protocols Project 2007-02 was initiated to ensure that real time system operators use standardized communication protocols during normal and emergency operations to improve situational awareness and shorten response time. The SDT developed a new COM-003-1 Standard that has yet to be posted and is dependent upon revising at least two other standards (CIP-001 and appropriate TOP Standard). COM-003 contains requirements that specify: 1. Use of three-part communication; 2. English language; 3. Common time zone; 4. NATO alpha-numeric alphabet; 5. Mutually agreed line identifiers; 6. The use of pre-defined system condition terminology such as those contained in the RCWG Alert Level Guide and EOP-002-2. This request is based on recent NERC Standards Committee direction to our team to incorporate the Reliability Coordinator Working Group's (RCWG) Alert Level Guide into a Standard. The consensus of our team is that a TOP Standard is the most appropriate location for the Transmission Emergency Alert language from the Guide as the energy emergency alert language is currently described in EOP-002-2. The RCWG Guide proposes the use of pre-defined system condition descriptions for use during emergencies for reliability related information. This guide was developed in response to a Blackout Report recommendation. Our team placed the energy cyber and physical security emergency alert language into CIP-001. Since the Real Time Operations SDT is currently modifying TOP-001 through 004, we seek your consent to incorporate the transmission emergency alert language to comply with the wishes of the Standards Committee. We believe that a TOP Standard is the most appropriate location for this language for the following reasons: • The levels of emergency conditions related to the transmission system is based upon maintaining the transmission system within Interconnection Reliability Operating Limits. • Your proposed TOP-001 R2 already requires the sharing of information of actual and anticipated transmission emergency conditions and the use of pre-defined terminology supports the efficient sharing of such information. The following text is appended here for the record. It is the OPCP SDT proposal for a revised TOP Standard that incorporates the TEA material. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 1 of 17 Effective Date: October 1, 2007 A. Introduction 1. Title: Transmission Operations 2. Number: TOP-004-3 3. Purpose: To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies; and to communicate transmission emergency alerts. 4. Applicability: 4.1. Reliability Coordinator 4.2. Balancing Authority 4.3. Transmission Operators 5. Proposed Effective Date: First day of first calendar quarter, one calendar year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter a year from the date of Board of Trustee adoption. B. Requirements R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs). R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency. R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator. R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes. R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area. R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.1. Monitoring and controlling voltage levels and real and reactive power flows. R6.2. Switching transmission elements. R6.3. Planned outages of transmission elements. R6.4. Responding to IROL and SOL violations. R7. Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have procedures for the communication of information concerning the transmission emergency alerts in accordance with the conditions described in Attachment 1-TOP-004-3. C. Measures Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 2 of 17 Effective Date: October 1, 2007 M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4. M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6. M3. Each Reliability Coordinator, Balancing Authority, Transmission Operator shall have

and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirement 7. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 3 of 17 Effective Date: October 1, 2007 D. Compliance 1. Compliance Monitoring Process 1.1. Compliance Monitoring Responsibility Regional Reliability Organizations shall be responsible for compliance monitoring. 1.2. Compliance Monitoring and Reset Time Frame One or more of the following methods will be used to assess compliance: - Self-certification (Conducted annually with submission according to schedule.) - Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.) - Periodic Audit (Conducted once every three years according to schedule.) - Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.) The Performance-Reset Period shall be 12 months from the last finding of non-compliance. 1.3. Data Retention Each Transmission Operator shall keep 90 days of historical data for Measure 1. Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2. If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer. Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor, The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data 1.4. Additional Compliance Information None. 2. Levels of Non-Compliance: 2.1. Level 1: Not applicable. 2.2. Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4. 2.3. .Level 3: Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 4 of 17 Effective Date: October 1, 2007 2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation: 2.4.1 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4. 2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4. E. Regional Differences None identified. Version History Version Date Action Change Tracking 0 April 1, 2005 Effective Date New 0 August 8, 2005 Removed “Proposed” from Effective Date Errata 1 November 1, 2006 Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006 Revised 2 December 19, 2007 Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance) Revised Errata Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 5 of 17 Effective Date: October 1, 2007 Attachment 1-TOP-004-3 Transmission Emergency Alert (TEA) Levels Introduction This Attachment provides the procedures by which a Transmission Operator or Reliability Coordinator can advise of actions taken to manage potential or actual Interconnected Reliability Operating Limit (IROL) violations. All three operating alert states (EEAs, TEAs and SEAs) are independent of each other and should be declared independently but they may also be declared concurrently. A. General Requirements 1. Initiation by Reliability Coordinator. A Transmission Emergency Alert (TEA) may be initiated only by a Reliability Coordinator at: 1) the Reliability Coordinator’s own request, or 2) upon the request of a Transmission Operator 1.1. Situations for initiating alert. A Transmission Emergency Alert may be initiated for the following reasons: • When all the available generation resources (would also include dispatchable load facilities that dispatch similar to generators on an economic basis) have been committed to respect an IROL in the pre-contingency state or; • When load curtailment procedures have been implemented to respect an IROL. 2. Notification. A Reliability Coordinator who declares a Transmission Emergency Alert shall notify all Transmission Operators and Balancing Authorities in its Reliability Area. The Reliability Coordinator shall also notify Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS) using the “System Emergency” category. Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify all Transmission Operators and Balancing Authorities in its Reliability Area and Reliability Coordinators when the alert has ended. B. Transmission Emergency Alert Levels Introduction Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 6 of 17 Effective Date: October 1, 2007 To ensure that all Reliability Coordinators clearly understand potential and actual actions taken to manage IROLs on the Interconnection, NERC has established three levels of Transmission Alerts. The Reliability Coordinators will use these terms when explaining actions taken to manage IROLs to each other. A Transmission Emergency Alert is an emergency communication protocol , not a daily operating practice, and is not an alternative to compliance with NERC reliability standards. The Reliability Coordinator may declare whatever alert level is appropriate, and need not proceed through the alerts sequentially. 1. Transmission Emergency Alert 1 (TEA 1) – All available generation resources committed to respecting IROLs. Circumstances: • The Reliability Coordinator or Transmission Operator foresees or is experiencing conditions where all available generation resources are committed to respect the IROL and/or is concerned about its ability to respect the IROL. 2. Transmission Emergency Alert 2 (TEA 2) — Load management procedures in effect to respect IROLs. Circumstances: • The Reliability Coordinator or Transmission Operator foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to: • Public appeals to reduce demand. • Voltage reduction. • Interruption of non-firm end use loads in accordance with applicable contracts (for emergency purposes, not economic reasons) • Demand-side management. • Utility load conservation measures • TLR 6 Note: TLR 5 would normally be implemented in advance of this alert state. Under some circumstances TLRs may not be available or effective and would not be called prior to this alert state. During TEA 2, Reliability Coordinators and Transmission

Operators have the following responsibilities: 2.1 Declaration period. The declaring Reliability Coordinator shall update the RCIS under “System Emergency” at a minimum of every hour until the TEA 2 is terminated. 2.2 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may be contributing to the alert level. Where appropriate, the Reliability Coordinators shall inform the Transmission Operators Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 7 of 17 Effective Date: October 1, 2007 under their purview of the pending Transmission Emergency Alert and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures and redispatching generation. The following additional actions should also be considered where appropriate: • Notification of ATC adjustments. Resulting increases in ATCs shall be communicated to the market via posting on the appropriate OASIS websites by the Transmission Providers. • Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the declaring Reliability Coordinator. • Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the declaring entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators. • Initiating inquiries on re-evaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of re-evaluating and revising SOLs or IROLs. 2.3 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses. 2.4 Actions Prior to Declaration of TEA 3. Before declaring a TEA 3, all available generation resources must be committed. This includes but is not limited to: • All available generation units are on-line. All generation capable of being on-line in the time frame of the emergency is on-line including quick-start and peaking units, regardless of cost. • Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost. • Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 8 of 17 Effective Date: October 1, 2007 • Operating Reserves. Operating reserves are being utilized such that the declaring entity may be carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program. 3. Transmission Emergency Alert 3 (TEA 3) — Firm load curtailment in effect to respect IROLs. Circumstances: The Reliability Coordinator or Transmission Operator foresees or has implemented firm load obligation interruption to respect an IROL. 3.1 Continue actions from TEA 2. The Reliability Coordinators and the declaring entity shall continue to take all actions initiated during TEA 2. 3.2 Declaration Period. The declaring Reliability Coordinator shall update the RCIS under “System Emergency” at a minimum of every hour until the TEA 3 is terminated. 3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities. 3.4 Re-evaluating and revising SOLs and IROLs. The Reliability Coordinator of the declaring entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Re-evaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the declaring entity who has requested an TEA 3 condition. SOLs and IROLs shall only be revised as long as a TEA 3 condition exists or as allowed by the Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised: 3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection. 3.5 Returning to pre-emergency SOLs and IROLs. Whenever the transmission systems can be returned to their pre-emergency SOLs or IROLs, the declaring Entity shall notify its respective Reliability Coordinator. 3.5.1 Notification of other parties. When an alert has been downgraded, the Reliability Coordinator shall notify via the RCIS the affected Reliability Coordinators, Transmission Operators and Balancing Authorities that their systems can be returned to their normal limits. Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 9 of 17 Effective Date: October 1, 2007 4. Transmission Emergency Alert 0 (TEA 0) - Termination. When the declaring Entity is able to respect IROL requirements and is no longer concerned with its ability to respect IROLs, it shall request its Reliability Coordinator to terminate the alert. 4.1. Notification. The Reliability Coordinator shall notify Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Transmission Operators and Balancing Authorities. RCIS Posting Examples Each RCIS posting should be clear and concise. If the actions are being taken as a result of a contingency, the contingency should also be identified as the cause. The following are examples of possible of RCIS postings: TEA 1 (name of RC) is declaring a TEA 1 on the (name of the interface). TEA 2 (name of RC) is declaring a TEA 2 on the (name of the interface). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of (type of load management procedures that have been or expected to be implemented ie voltage reduction, curtailable load reductions) of relief has been (or is expected) to be implemented to respect the limit. These actions are expected to last the next (length of time – hours/days) and should be sufficient to prevent the need for Firm load shedding. TEA 3 (name of RC) is declaring a TEA 3 on the (name of the interface). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of Firm Load curtailments have been (or is expected) implemented to respect the limit. These actions are expected to last the next (length of time –

hours/days). Contingency Example If the TEA is being declared as a result of a contingency the message could be modified simply by adding the contingency description as below: (name of RC) is declaring a TEA 2 on the (name of the interface). This is a result of a contingency on (name of the interface or contingent element). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of (type of load management procedures that have been Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 10 of 17 Effective Date: October 1, 2007 or are expected to be implemented i.e. voltage reduction, curtailable load reductions) to respect the limit. These actions are expected to last the next (length of time – hours/days) and should be sufficient to prevent the need for Firm load shedding. Updates When updating postings only significant changes need be identified. The following is appropriate: (name of RC) remains in a TEA (2 or 3) on the (name of the interface). (amount of MW relief) of (type of load management procedures that have been or are expected to be implemented i.e. voltage reduction, curtailable load reductions, firm load reductions) have been implemented (description of the change i.e. increased/reduce by amount of MW change or identify no change). Standard TOP-004-3 — Transmission Operations Example #1 IROL violation on “X” No Global Adequacy Concerns IROL “X” 500 MW - A to B 300 MW - B to A Intertie Limit Intertie Limit Imp 300 Imp 200 Exp 200 Exp 100 EEA 1 No 2 No 3 No TEA 1 Yes 2 Yes 3 Yes In this example the available generation in A is in excess of its load requirements. The available generation in B is less than its load requirements. Area B will be relying on the full transfer capability of the interface “X” plus an additional import of 100 MW to the maximum limit on the intertie in Area B. With the implementation of the interruptible load and V/R the firm load requirements in B cannot be met without the use of Firm load shedding. • In this scenario an EEA is not required as the BA is able to meet its global BA Total Load 2,500 MW BA Total Gen 2,900 MW BAImpLimit500MW Zone A Zone B Load 1,500 MW Load 1,000 MW Gen available 2,800 MW Gen available 100 MW Imp 0 MW Imp 100 MW Exp 0 MW Exp 0 MW Interruptible 50 MW Load Interruptible 50 MW Load V/R 50 MW V/R 50 MW Balancing Authority “X” Adopted by Board of Trustees: November 1, 2006 Page 11 of 17 Effective Date: October 1, 2007 Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 12 of 17 Effective Date: October 1, 2007 load/generation requirements. • When this situation is forecast a TEA 1 should be issued to indicate the potential concerns with the ability to respect the IROL limit “X” without the use of load management procedures. • When load management procedures are implemented in Real Time to respect the IROL “X”, a TEA 2 should be issued. • When Firm load is curtailed to respect the limit a TEA 3 should be issued. Standard TOP-004-3 — Transmission Operations Example #2 Global Adequacy Deficiency No IROL Violation IROL “X” 500 MW - A to B 300 MW - B to A Intertie Limit Intertie Limit Imp 300 Imp 200 Exp 200 Exp 100 EEA 1 Yes 2 Yes 3 No TEA 1 No 2 No 3 No In this example the available generation in A is less than its load requirements. The available generation in B is less than its load requirements. There is a Global Adequacy deficiency after considering full import capability and utilization of interruptible load and V/R. BA Total Load 2,500 MW BA Total Gen 1,800 MW Zone A Zone B Load 1,500 MW Load 1,000 MW Gen available 900 MW Gen available 900 MW Imp 300 MW Imp 200 MW Exp 0 MW Exp 0 MW Interruptible 100 MW Load Interruptible 50 MW Load V/R 50 MW V/R 50 MW Balancing Authority “X” Adopted by Board of Trustees: November 1, 2006 Page 13 of 17 Effective Date: October 1, 2007 Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 14 of 17 Effective Date: October 1, 2007 • EEA procedures should be followed • There is no need for a TEA to be issued Standard TOP-004-3 — Transmission Operations Example #3 Global Adequacy Deficiency IROL Violation IROL “X” 500 MW - A to B 300 MW - B to A Intertie Limit Intertie Limit Imp 300 Imp 200 Exp 200 Exp 100 EEA 1 Yes 2 Yes 3 No TEA 1 Yes 2 Yes 3 Yes In this example the available generation in A meets its load requirements. The available generation in B is less than its load requirements. There is a Global Adequacy deficiency after considering full import capability. There is also an IROL violation at “X” in the direction of A to B to meet the load requirements in B depending on where load management procedures are implemented. Adopted by Board of Trustees: November 1, 2006 Page 15 of 17 Effective Date: October 1, 2007 • An EEA 1 and a TEA 1 should be issued to identify the potential issues BA Total Load 2,500 MW BA Total Gen 1,700 MW BAImpLimit500MW A B Load 1,500 MW Load 1,000 MW Gen available 1,600 MW Gen available 100 MW Imp 300 MW Imp 200 MW Exp 0 MW Exp 0 MW Interruptible 100 MW Load Interruptible 50 MW Load V/R 50 MW V/R 50 MW Balancing Authority “X” Standard TOP-004-3 — Transmission Operations Adopted by Board of Trustees: November 1, 2006 Page 16 of 17 Effective Date: October 1, 2007 • When load management procedures are implemented to manage the transfer from A to B a TEA 2 should be issued (assumes B will be deficient before the global deficiency occurs). • An EEA 2 should be issued when load management procedures are being implemented in A to manage global requirements. • TEA 3 should also be issued when Firm load is shed in B to meet the load requirements in B while respecting the IROL. Standard TOP-004-3 — Transmission Operations Example #4 Transaction Curtailments IROL “X” 500 MW - A to B 300 MW - B to A Intertie Limit Intertie Limit Imp 300 Imp 200 Exp 200 Exp 100 EEA 1 No 2 No 3 No TEA 1 No 2 No 3 No In this example there are no global adequacy concerns. There is an export transaction in B that is causing a limit concern on “X” in the A to B direction. With the available generation in B plus the transfer capability there is no concern for violating the IROL limit. The transaction is creating a situation where it will be required curtailed at some point to prevent the IROL violation. Assuming the TLR procedure would be effective at relieving this constraint regardless of the TLR level (at either the TLR 3 or 5 level) no TEA would be required as there is no concern that the IROL can’t be respected with control actions that don’t involve load management procedures. BA Total Load 2,500 MW BA Total Gen 2,500 MW BAImpLimit500MW A B Load 1,500 MW Load 1,000 MW Gen available 2,000 MW Gen available 500 MW Imp 200 MW Imp 0 MW Exp 0 MW Exp 100 MW Interruptible 100 MW Load Interruptible 50 MW Load V/R 50 MW V/R 50 MW Balancing Authority “X” Adopted by Board of Trustees: November 1, 2006 Page 17 of 17 Effective Date: October 1, 2007
Individual

Chris Scanlon
Exelon
Yes
Yes
Is there a typo in the question? TOP-001 does not have a rev 3. Assuming the intent is to refer to TOP-001-2, R4 we agree.
Yes
Follow existing Guidelines, GADS states “well in advance” as notification for “Planned” outages. This typically means more than 30 days in advance. PJM uses the 30 day definition for “Planned”. Nuclear / INPO uses 28 days (4 weeks) from an INPO definition for “Planned”. 30 days seems to be a reasonable requirement.
No
In general, Exelon supports the revisions and appreciates the work being done by the SDT to consolidate and clarify the requirements. We have some concerns with the langauge in TOP-001-2 R4. "Coordinate" - We believe this needs to be better defined. "Known or expected to have a reliability impact" - Reliability impact needs to be defined better, can measures be identified, such as; cause a system to violate a limit under expected conditions? Consider adding the words “in the judgment of the TOP ” before the word “expected.” Otherwise this may become a point of contenetion and difficulty during an audit. If the GO is not removed (see question 2)the GO is not likely to have the ability to know what reliability impacts its actions might have. "other reliability entities" - needs to be defined. "Unless conditions do not permit such coordination" - if this clause is getting at the issue of time not available, consider “unless based on the reasonable judgment of the TO, considering the facts and circumstances at the time, conditions do not permit such coordination.” We feel the point of the requiremnts should be when a GO/TO knows or reasonably should know that an action will have a substantial adverse reliability impact on another operating entity (define), the GO/TO should inform the other entity and consider that other entity’s input in deciding how to operate, if time permits.
Individual
Michael J. Sonnelitter
NextEra Energy Resources, LLC
Yes
Yes
No comment.
Yes
No comment.
Yes
Individual
Harvie Beavers
Colmac Clarion
Yes
Yes
Particularly since R2 contains no requirement for communications concerning notification of any problems or communication with the GOP. Likely the first time GOP will be aware of condition is at failure of RC/TO efforts to resolve same.
Yes
Assume this is System Operating Limit and Interconnect Reliability Operating Limit (need to cite for first time acronym use as was done with 'BES' in purpose statement). Unsure of exact setpoint of reporting, but would likely be at anytime load approaches or exceeds planned or immediately available generation; perhaps within 2-5% greater then parity.
Yes
Yes
Current policy under some existing contract operators requires initial notification on a rolling 3 year plan and additional

notification to 'dispatcher' at 30 days. Generally, verbal notification is also conducted between generating facilities and Transmission operator on a much shorter and timely basis additionally. Transmission/Distribution company has a similar long range, and short notification cycle.
Yes
During 'blackout' that resulted in this program, GOP's received more intial information on problem and expected recovery from CNN then from 'chain of command'. If response is expected inclusion in information stream must also be included.
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
No
PacifiCorp has no specific subset of SOLs to suggest, however, they must be clear and easily identifiable and measurable. Suggested subsets should be included in the next comment phase for this SAR.
Yes
Yes
The appropriate number of days should be established on a region-wide basis, not a country wide basis. Each region has unique infrastructure that requires specific advance notice.
Yes
Group
Real Time Best Practices Standards Study Group
Frank Koza
No
The Real-time Best Practices Standards Study Group (RTBPSSG) feels that the deletion of TOP-004-2, R4 (Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes) does not provide an adequate level of reliability for the operation of the Bulk Electric System (BES) and the reasoning provided for the removal is flawed. The RTBPSSG believes that this is an important consideration for operations that should not be deleted and that with more deliberations an acceptable measure for such a requirement can be developed. The concept of operating in a known state has long been a fundamental concept of reliable system operations and if this requirement is deleted then there is no requirement to cover this concept. The idea of operating to preclude IROLs or to return to within the limit in Tv does not adequately address this concern.
Group
PJM's NERC and Regional Coordination Department
Patrick Brown
Yes
PJM supports the intent and the concept of comparability as intended by this requirement. However, PJM would note that TOP Emergency Procedures are not identical and are designed around the reliablity needs and capabilities of the individual TOP. When dealing with compliance, the interpretation of what is and what is not comparable could have unintended consequences.
Yes
The data obligations for GOPs to coordinate with its TOPs is covered in TOP-001-2 R1. The operational obligations for GOPs to coordinate with TOPs is covered in IRO-005. IRO-005-3 R1 places a requirement on the RC to have access to operating data (which specifically includes planned generation outages – R 1.9). Thus the RC already has the responsibility to get the data in question. Given that the RC has the authority to request and obtain that data, one could argue that there is no need to also mandate that the GOP coordinate the same data, since that obligation already lies with the RC - see R4).
PJM agrees that reporting should be based upon and restricted to reliability issues. Given the broad scope of the term

SOL as defined in the NERC Glossary, PJM agrees that the requirement should be limited to a subset of the SOLs PJM proposes: 1. The TOP requirement on limit reporting parallel the RC requirement on IROLs 2. The TOP report violations (not exceedences) of any limit predefined by the TOP to be an essential limit (i.e. for a defined local condition that is deemed by the TOP to be of special concern and is not covered by any predefined IROL). This approach provides a TOP the flexibility, when appropriate, to go beyond the definition of BES and to use reliability considerations rather than arbitary formulae to drive its operational reporting.
Yes
PJM agrees that there is no need to include a requirement that focuses on switching procedures.
No
A mandated common time-period would likely conflict with some already FERC-approved procedures. Moreover, a common timing requirement will likely as reduce the benefits and flexibility of some procedures, as it would provide benefits to others.
Yes
Group
Southern Compnay
Hugh Francis
Yes
Yes, the phrase should be reinstated. Also, these actions should be coordinated by the Reliability Coordinator(s). Thus, we believe the verbiage should ultimately be: “provided that the requesting entity has implemented its comparable emergency procedures as coordinated by the Reliability Coordinator(s)”.
No
The GOP needs to communicate problems that could impact normal operation.
The subset will be pre-contingency IROL exceedences, post-contingency IROL exceedences, and real-time facilities experiencing SOL exceedences.
Yes
Redundant requirements in separate standards are both confusing and waste resources.
No
No time limit needs to be established. Entities need to be able to plan short term outages, generation and transmission. The Eastern Interconnection presently has an advanced outage notification through the NERC SDX.
No
TOP-001 R2: The phrase “shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities” could cause compliance issues due to the resulting subjectivity of the identification of other reliability entities. Recommend that it replaced with “shall coordinate its respective operations known or expected to have a reliability impact on adjacent reliability entities”. It should be the responsibility of the adjacent reliability entity to further coordinate, if necessary, other appropriate reliability entities. The Measures and VSLs would need to be modified accordingly. TOP-002 R2 uses the word "plan" as a verb, and then it is referenced in R3 as a noun. This is propagated in the Measures and VSLs. Suggest the following wording change in R2: The Transmission Operator shall have a coordinated plan…… TOP-003 R1.1 - suggest that "Long term" be removed and replaced with "Planned". "Long term" could be interpreted to mean an outage that will not occur for quite some time (long lead time), or an outage that will occur sooner but will last for a long time. All outages should be communicated. R1.2 - Disagree with this requirement. We recommend that it be struck. The TO and the BA must be able to specify formats that can be utilized by their processes to ensure reliability.
Individual
James H. Sorrels, Jr.
American Electric Power
Yes
AEP would suggest that the phrase be reinstated with a change of the word “implemented” to “taken into consideration”. It is important that entities not solely rely on emergency assistance when alternatives may be available. The timing itself may necessitate alternative approaches.
Yes
AEP appreciates the removal of redundant requirements, where possible to do so. We do not see the need for the GOP to be involved.
Yes
While it is expected that the Transmission Operators work in conjunction with the Reliability Coordinators to mitigate most SOL violations, a NERC requirement to report all SOL violations seems impractical. The IROLs provide a clear and logical subset of SOLs that should be reported to the RC.
Yes

Please note the typographical error in question 4. TOP-001-3 in question 4 should read TPO-001-2.
No
The current rules for each region are followed today and coordination is done very well. Seams agreements address the coordination across regions. Therefore, a country-wide period is not necessary from a reliability perspective. If it is otherwise determined to be necessary, AEP believes that it should be done at the IROL level since, by definition, these are the situations with wide area impact.
Yes
Individual
Jianmei Chai
Consumers Energy Company
Yes
An Entity can not be required to take actions for another if the requesting entity has not taken all steps available to them to correct the situation.
No
No
Communication of planned or scheduled outages should take place in the planning phase. Communication should be as early in the phase as possible for all TOs GOs and BAs effected by the outage. To have a nationwide standard is too confining and removes possible flexibility that can come from open communication. TOP-003-0 requires communication of outage information on a daily basis.
No
TOP-003-1 R1.1 needs to be more specific in identifying the ‘equipment’ to be considered for inclusion.
Individual
Brent Ingebrigtson
E.ON U.S.
Yes
No
The requirement should state that the Generator Operators should be required to “coordinate” with their respective TOP not simply provide data.
No
All SOL exceedances on the BES should be reported to the RC and corrective actions should be coordinated with the RC.
Yes
No
The RCs already have advance notification requirements which TOPs must follow. Most BES facilities have limited impact on neighboring systems. Depending on the level of notification, this could impose an undue burden on Transmisson Operators and field switching personnel in performing needed maintenance. The Regions should identify a subset of facilities (similar to the ECAR Facility Outage Notification Table) subject to advanced notification requirements. Should a country-wide advance notice time period be established it should only apply to 200kV and above.
Yes
Individual
Darryl Curtis
Oncor Electric Delivery
Yes
This phrase should be reinstated.
Yes
GOP should be deleted from this requirement.
Yes
Comments: Report all SOLs that require firm load to be dropped to return transmission elements within limits.

No
Comments (including # of days if appropriate): Oncor Electric Delivery does not believe a country-wide notification period is necessary. As each interconnection has it’s unique characteristics, there is no assurance that a common advance notification period would work for all. Additionally, setting a common date within a NERC standard seems inconsistent with the intent of reliability based standards. Advanced notification seems to be more of a market function and is not reliability based.
Group
WECC
Mike Davis
No
Leave phrase deleted and current red line indicates that this is only TO to TO assistance, we believe this is too restrictive and reinstate BA's and GO's.
No
No
All SOL's should be reported to the RC
No
We believe there is a need for clear agreements
Yes
We believe outage notification to the RC for all equipment 100kV and above, and all generator outges of 50MW and above should be a mininum of 96 hours notice in advance.
Yes
Individual
Nied
Con Edison System Ops
Yes
I justify this by saying that this phrase should already included in an operating agreement between the TO's. ...but, having this wording in the standard as well will serve to ensure that TO's have their documents and agreements up to date.
No
The GOP wording should remain.
Let me start out by saying that ConEd reports all SOL's that occur on its system to the NYISO, our RC/BA/TOP. Only those SOL's should be reported to a higher authority (NPCC and above) that result from the TO operating its system in a state which is not allowed. That is, real time SOL's that arise from the TO operating its system on a post-contingency basis due to an exception granted by its RC should not be reported.
Yes
It should be deleted. I see no need for keeping the R2 wording in there. It's confusing and leaves too much up to interpretation. As stated above, the "coordination of operations" wording in R4 would suffice.
Unless the piece of equipment is in a direct neighboring system, what utility would this offer to a TO? "Operations are already coordinated" amongst neighboring TO's with regard to tie-lines. It would not offer much in the way of information on how we operate our system. However, ConEd already sends notification of all of its approved outages on the Bulk Electric System to the NYISO via email automatically. So, I dont think it would be difficult to do if someone decides that they want 7 or 10 day notifiation on something. If this requirement came into being, the NYISO could then disburse COnEd's outage info to NPCC and rest of the East. A hard-line 7 or 10 day rule will be tough to enforce though. Many outages get approved much closer to the actual date...many within 2 days of the start.
No single concern. Each revision should be analyzed on its own merits.
Individual
Kasia Mihalchulk
Manitoba Hydro
Yes
Yes

No
IROL's only
Yes
No
We do not believe there is a reliability need to establish an industry wide advance notification procedure for transmission outages. We believe that the need for advance notification of transmission outages should be identified completely between the TOP and RC in their outage coordination procedures.
Yes
Individual
Ed Davis
Entergy Services
No
There could be situations in which the TOP requesting support cannot implement comparable procedures. For instance, if reconfiguration from a neighboring system would resolve the situation, but reconfiguration on the requestor’s system would not.
No
The status of large generators can have a reliability impact on other reliability entities, and they should be included in this standard.
Instances where an IROL is exceeded should be required to be reported to the RC. It should be left to the RC and TOP to agree to other SOLs that are important enough to be required to be reported to the RC.
Yes
No
There are processes already in place to ensure that outages are coordinated between affected systems. Creating a nation-wide requirement to set an advance notice time is not in the best interests of reliability. Rather flexibility should be allowed to coordinate and agree upon required maintenance activities that are necessary to ensure continued reliability.
Yes
Individual
Greg Rowland
Duke Energy
Yes
No
We believe it’s critical for the GOP to coordinate operations with the TOP.
Yes
Given that geography varies, system interdependencies and ratings philosophy, TOP/RC should agree on what to report.
Yes
No
This comment form is not the right place to address this issue. We would have significant concerns with the idea – too much to support a requirement that hasn’t been drafted yet. Existing processes are in place between neighboring entities to exchange this type of information.
No
- TOP-001 R2 Need to change “affected” to “adjacent”, and in the VSLs. - TOP-001 R4 Change “other” to “adjacent”, and in the VSLs. - TOP-001 R4 If coordinating means that we’re posting the information on SDX, then we are in agreement. - TOP-001 R6 Need clarification on what Tv means. Will we be able to establish variable Tvs based upon the specific IROLs? - TOP-001 R7 Where has this requirement been moved to, or has it been deleted? If it has been deleted, why? - TOP-002 R1 Need to add (N-1) after Contingency, and in the VSL. - TOP-002 R2 does not require a written plan but R3 requires notification of entities in the plan. - TOP-002 R3 VSLs should be changed back to what they were before this revision. - TOP-003-1 R1 The term “NERC Functional Model” should not be used in a requirement because it reduces clarity, due to fact that the NERC Functional Model is evolving over time.

Individual
Kirit Shah
Ameren
Yes
No
GOPs need to coordinate their activities. For instance, a small tube leak might not mandate an immediate outage for a plant electrically near a known SOL/IROL area. To the extent the GOP and TOP coordinate when the outage to repair this condition will occur, BES reliability benefits.
Yes
No
Agreements (formal or informal) are necessary to describe the conditions under which the coordinated switching in TOP-001 takes place. It will be impossible for Transmission Planners to properly analyze the conditions that can be expected if there are no “rules” for operation.
No
First, the definition of planned outage is anything but an industry standard. So the rules around timing are putting the cart before the horse, And, anything in “days” is not practical given the need to get to short-term planned maintenance and the impacts of weather and forced outages on these planned outages. If a notification time is absolutely deemed necessary, 30 minutes to 1 hour would be workable under a mandatory, enforceable NERC standard framework.
Yes
The team has done a significant amount of work in getting these standards cleaned up. There was too much duplication and uncertainty.
Group
SERC OC Standards Review Group
Jim Griffith
Yes
Also, it is not clear in the context of TOP-001 what kinds of assistance an operator of transmission should give to another Transmission Operator (for example, refer to EOP-001, R1 for clarification)
No
Yes
The subset of SOLs, other than IROLs (which must be reported), should be agreed upon between each Reliability Coordinator and the TOPs within the RC’s reliability area.
Yes
If the SDT agrees with deleting R2, we suggest that R1 should be included in TOP-002 and TOP-004-3 retired.
No
A time limit does not need to be established. Entities need to be able to plan short term outages, both transmission and generation when conditions permit in order to minimize impacts to the reliability of the system. For example, a transmission line in need of maintenance might only be available upon the outage (forced or planned) on a particular generator. With a standard in place, this opportunity would be missed. Delaying maintenance on a transmission line puts it at a greater risk of a forced outage.
Yes
TOP-001 R2 - The phrase "shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities" could cause compliance issues due to the resulting subjectivity of the identification of other reliability entities. We recommend that it replaced with "shall coordinate its respective operations known or expected to have a reliability impact on adjacent reliability entities". It should be the responsibility of the adjacent reliability entity to further coordinate, if necessary, other appropriate reliability entities. The Measures and VSLs would need to be modified accordingly. Top-001, Requirement 4 - we suggest changing “other reliability entities” to “adjacent reliability entities”. TOP-002 R2 uses the word "plan" as a verb, and then it is referenced in R3 as a noun. This is propagated in the Measures and VSLs. We suggest the following wording change in R2: “The Transmission Operator shall have a coordinated plan...... “ TOP-003 R1.2 – We disagree with this requirement and we recommend that it be struck. The TOP and the BA must be able to specify formats that can be utilized by their processes to ensure reliability.
Group
FirstEnergy Corp
Doug Hohlbaugh
Yes

We support reinstating the proposed text and it should be clarified, provided that it can be shown that the action requested to assist the other party will mitigate an adverse reliability problem. FE suggests that the text should indicate "provided that the requesting entity has implemented its comparable emergency procedures capable of lessening or mitigating the impact of the emergency and that the assistance requested will help to alleviate an adverse reliability problem."
No
TOP-001-2 R4 requires the actions of the GOP be coordinated with impacted entities while TOP-003-1 R4 requires the GOP to provide data to the TOP and BAs. These are two completely different aspects of the BES operation and both need to be addressed by a standard.
Yes
The question as written does not lend itself to a yes/no answer, the selection of yes was made to indicate that we agree some subset of SOL, when exceeded, warrants the a TOP notification to the RC. FE believes that the appropriate subset are those SOLs that are associated with a previously defined Interconnection Reliability Operating Limit (IROL) as determined via the FAC-014 reliability standard.
Yes
Yes, we agree with the recommendation to delete TOP-004-4 R2. Since this change would leave only one requirement within the TOP-004-4 standard, we urge the team to consider incorporating the requirement into another standard. One suggestion is consider adding the requirement to standard IRO-005-3 titled "Reliability Coordination — Current Day Operations". This could be added as a new requirement of IRO-005-3 or possibly a sub-requirement of requirement R11 of the IRO-005-3 standard. Alternatively, the requirement could be placed into the TOP-001 standard.
No
We do not believe there is a reliability need to establish a common industry wide lead-time for planned BES facility outages. It should be left to the RC and the applicable entities that it monitors (TOPs, GOPs) to establish agreed upon outage coordination procedures. In fact, it should not be expected that a minimum lead-time must always be rigidly adhered to. Consider that many transmission lines can only be taken out of service during a generator outage. If generator unit experienced a forced outage that would permit certain transmission lines to be maintained, such maintenance should not be delayed to simply adhere to a specific lead-time requirement. The RC's and their monitored entities should be given the flexibility to develop a process that is suitable to meet their needs.
No
The drafting team's response to FE's fifth comment in the Draft 1 Question 12 is not sufficient for us to understand their thought process on the matter. Our prior comment raised a concern with the removal of TOP-007-0 R3 that states, "A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load …" The SDT responded that this matter is covered in EOP-001-0, Requirement R3.3 that states, "R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: … R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities." The SDT is proposing to retire PER-001 and FE believes the PER-001 requirement R1 and its associated measure M1.4 should be re-enforced within the TOP standards. This operator authority was a focal point of recent readiness evaluations within the industry and should be explicit within a TOP requirement. We would appreciate further explanation from the SDT if they feel the change is still not required. FE disagrees with the SDT's response to our comment on Draft 1 Q4 which questioned which contingencies are required to be evaluated within the operating horizon. The prior TOP-002-2 requirement R6 stated "R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements." This concept is lost in the newly proposed TOP standards. In responding the SDT stated that "the Transmission Operator is not limited to single Contingencies or bus faults but must study any and all conditions that may result in exceeding any of its System Operating Limits during anticipated normal conditions as stated in the Requirement. The potential Contingencies to be studied are limited to those spelled out in the TPL standard." FirstEnergy does not agree that there is an expectation to cover all TPL contingencies within the operating horizon. As vetted by industry in the recent proposed and subsequently withdrawn SAR that proposed to evaluate "credible multiple contingencies" it is clear that studies within the planning and operations horizon are distinctly different and that there is no expectation to cover events in real-time or within the operating horizon (next day, next month, through one year out) beyond single contingency. We ask the SDT to clarify their comment in this regard. We would like the SDT to explain why it found the need to introduce the term "each" in requirement R1 of TOP-002-1. As re-worded, the focus of the compliance audit may become too structured on strict adherence to each directive rather than the TOP meeting the intent of the RC's directives. If the wording remains, we believe the VSLs can be better graded and that missing a single directive should not warrant a severe VSL. Many of the proposed VSLs use a quartile approach (0-25%, 25-50%,50%-75% and >75%) of gauging if some reliability action was missed. FERC in its VSL Order dated June 19, 2008 took exception to the quartile approach and felt it violates its Guideline 1 "Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance" see paragraphs 19 through 21. The VSL DT revised the VLS that previously used a quartile score to reflect a 0-5%, 5%-10%, 10-15% and >15% graded VSL approach. Its suggested that the SDT reconsider its use of quartile VSLs. We believe the VSLs for TOP-001-2 R6 violates the Commission's Guideline 4 established in their VSL order. The VSLs are based on the number times the

TOP did not act to mitigate the magnitude and duration of an IROL exceedance within its Tv. However, the associated requirement states “The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL’s Tv.” Note that the requirement talks about “an IROL” in the singular. Thus, failure to act on one occasion is a single violation. Failure to act on two occasions is two separate violations not a higher VSL. We suggest that a binary Severe VSL be selected or that you modify the requirement to consider IROLs in the plural. In TOP-003-1 R1.1 second bullet the SDT introduced a new requirement that for data exchange related to equipment at voltage levels below the BES and left the need for this data at the discretion of the TOP or BA. FirstEnergy believes the inclusion of equipment lower than normal BES levels should not be introduced on an ad-hoc standard by standard basis. Rather, if such equipment is deemed necessary for the reliability of the BES then the Facilities may need to be subject to other reliability standards such as vegetation management, preventative maintenance, etc. Inclusion of such equipment should be a registration issue handled through the Regional Entity and not within individual standard requirements. However, providing such data could be requested and provided on a voluntary basis, but if the equipment is deemed essential for BES reliability other standards likely apply.
Group
Dominion Resources Inc.
Jalal Babik
Yes
As currently written an entity could be found non-compliant for not providing emergency assistance to a requesting entity that is not willing to help itself. That punishes the wrong party.
Yes
We support the change. FERC Codes/Standards of Conduct prohibit transfer of non-public transmission information to ‘marketing entities’. Most staffs on the ‘transmission side’ of the industry (TO, TOP, TP, RC) are reluctant to share any non-public information with those on the ‘generation side’ (GO, GOP) because they are unsure whether or not those staffs are deemed ‘marketing entities’.
Yes
In addition to IROLs, the subset of SOLs that need to be reported should include any other SOL exceedances that the RC requests notification of and, in the Eastern Interconnection, any other SOL exceedances associated with permanent, reliability flowgates as defined in the NERC Book of Flowgates.
Yes
It is not clear what an agreement between TOPs to “specify switching” of tie lines is supposed to be. If it is supposed to be an interconnection agreement, those are usually between Transmission Owners. Requirement R2 can be deleted.
No
(including # of days if appropriate): We don’t recommend a country-wide advance notice. However, we agree that it is within the purview of the Reliability Coordinators to reach agreement with the applicable entity and set outage reporting requirements to meet their reliability assessment needs without the development of a new NERC reliability standard.
Yes
TOP-001 uses the term ‘reliability entities’ in the purpose statement while TOP-003 uses the term ‘functional responsibilities’. The Functional Model uses the term ‘Responsible Entities”. We suggest that NERC and the SDT make every effort to use consistent terms. We continue to have concerns with the current standards review/approval process. Having to make comments on new draft standards that are predicted upon other draft standards that have not been approved is a non-productive process. As stated in the implementation plan “Changes made in this project to TOP-005-1, R1; TOP-007-0, R4 are dependent on corresponding changes being approved in Project 2006-06 Reliability Coordination: • COM-001-1: Telecommunications • COM-002-2: Communications and Coordination • IRO-001-1: Reliability Coordination – Responsibilities and Authorities • IRO-002-1: Reliability Coordination – Facilities • IRO-014-1: Procedures to Support Coordination between Reliability Coordinators • IRO-015-1: Notifications and Information Exchange between Reliability Coordinators • IRO-016-1: Coordination of Real-Time Activities between Reliability Coordinators • PER-004-1: Reliability Coordination – Staffing • PRC-001-1: System Protection Coordination”
Group
Northeast Power Coordinating Council
Guy Zito
Yes
It is expected that further details of emergency assistance to be provided would be covered in Operating Agreements.
No
We believe there are occasions when a GOP may need to take actions that would require coordination with or notification of the RC/TOP/BA or others who could be impacted. At this time it is not clear what other standards could obligate the GOP to do so if the GOP were removed from this requirement.
No
System Operating Limits are meant to “ensure operation within acceptable reliability criteria”. Understanding that there is a subset of more critical SOL’s defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the

actions being taken to address the exceedances which can be accomplished via SCADA or other means of action and communication when necessary.
No
Operating Agreements cover activities other than switching. We believe the requirement should be retained but any duplication eliminated.
No
While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region. Such notification requirements should be established within each region based on the needs of the RC.
No
We disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time." SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability? Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? TOP-002-3 M1--Power flow study results will not be available for those days where studies are not required. Those days may be considered pre-studied or a normal “studied” state. How is this to be measured? TOP-002-3 R2, R3 – A plan should be required when the review warrants it and should include both IROL and SOL. In a normal state there may already be existing coordination between reliability entities with no need to re-communicate. TOP-003-1 R1: Reference to the Functional Model in the requirement may not be appropriate. This requirement may be clearer if the specific responsibilities are included. R1.1 “Long Term Outages” should be defined or clarified. What about other outages that are potentially impactive? In general, it is not clear that the data specification includes real time communications or operational planning requirements. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some voice recorders are designed to retain data for 90 days. Have data recordings stored longer than 90 days only if requested by the RC or TOP.
Individual
Tony Kroskey
Brazos Electric Power Cooperative, Inc.
Yes
No
If a GOP is to comply with directives from a TOP in R1, then a requirement "to coordinate operations" is needed in R4.
Yes
The IROL subset needs to be reported.
No
Either leave TOP-004-3, R2 as is or move a requirement for an Agreement into TOP-001-3, R4.
No
At this time I see no reliability benefit for this requirement.
No
See responses to previous questions.
Group
Midwest ISO Stakeholders Standards Collaborators
Jason L. Marshall
No
When a compliance audit is conducted, the compliance auditor will not be evaluating a third party TOP to determine if they implemented all of their comparable procedures prior to requesting emergency assistance. They will simply review if the TOP being audited responded to the request for emergency assistance. If they did not, they are not necessarily in violation of the requirement because the requirement does recognize legal restrictions for not responding. Thus, if a third party TOP requested the audited TOP to shed load but had not done so themselves, the audited TOP may have appropriately and compliantly refused because their state laws and regulations prevent them from shedding load for neighbors unless they are doing the same.
No
What if the unit is a reliability must run unit? With this requirement in place, the GOP may be more proactive in keeping the unit running (i.e. willing to take a greater risk damaging the unit if there is already a problem with the unit). Without

the requirement, the GOP may shut the unit down at the first sign of any problem.
All SOL exceedances should be reported to the Reliability Coordinator. The Reliability Coordinator has the ultimate reliability authority. If the RC is not made aware of an SOL exceedance, how can the RC evaluate if the exceedance is actually approaching an IROL? Further, multiple SOL exceedances can be a sign of a greater reliability problem that the RC needs to rectify.
Yes
No
We do not believe there is a reliability need to establish an industry wide advance notification procedure for transmission outages. We believe that the need for advance notification of transmission outages should be identified completely between the TOP and RC in their outage coordination procedures. In fact, we believe such a requirement could actually be a detriment to reliability. Consider that many transmission lines can only be taken out of service during a generator outage. If the generator were to trip, the transmission line could not be taken out of service for lack of sufficient advance notice delaying the maintenance of the line and, thus, increasing the potential for the line to be forced out. It is not clear what reliability benefit could even be achieved by having an industry wide advance notification requirement. We believe that should such a requirement become a reality, there will be further reliability detriment as TO/TOPs delay maintenance in a struggle to transition to comply with such a requirement.
No
We believe removing the requirements for SOLs in this standard will make it unacceptable to FERC. Thus, the drafting team will have to start over when FERC remands the standard. The VSLs for TOP-001-2 R2 are based on the number of times the TOP did not inform the RC of Emergency conditions. Over what time period does this apply? In perpetuity? From last compliance audit? We believe the VSLs for TOP-001-2 R6 violates the Commission's guideline 4 established in their VSL order. The VSLs are based on the number times the TOP did not act to mitigate the magnitude and duration of an IROL exceedance within its Tv. However, the associated requirement states "The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv." Note that the requirement talks about "an IROL" in the singular. Thus, failure to act on one occasion is a single violation. Failure to act on two occasions is two separate violations not a higher VSL. We suggest that a binary Severe VSL be selected or that you modify the requirement to consider IROLs in the plural. In TOP-002-3, the drafting team should consider making R2 a sub-requirement of R1. Isn't it a sub-component of the assessment the TOP must have in R1? R3 should be made sub-requirement of R2. M1 deviates from R1 in that M1 says that the TOP shall have evidence that it performed an assessment while R1 says it shall have an assessment. Likewise, the VSL differs from the requirement in the same way and should be made to match the requirement. In TOP-003-1, we note that R3 requires the BA to distribute its data specification but there is not a similar requirement to have a data specification like R1 for the TOP. We believe R3 belongs in the BAL standards. We also suggest that the VSLs for R4 and R5 could be graded to include multiple levels. In R4, we believe the additional VSLs could be defined based on the percentage of data that is not supplied. The VSLs for R5 could be graded based on the number TOPs and BAs that the TOP did not supply data and information to. We further believe that the portion of the requirement in R5 that applies to the BA should be moved to the BAL standards. In TOP-004-3, M1 appears to be a measure of non-compliance with R1. Aren't measures supposed to identify how compliance is measured not non-compliance? The VSLs measure non-compliance.
Group
FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool
Frank Gaffney, Regulatory Compliance Officer
Yes
This is a tough one to answer, there are conceivably two types of timelines for emergencies, e.g., an emergency where response is required within minutes vs. response during a longer period of time. If a response is needed in minutes, such as post-contingency with a facility within a 10 minute emergency rating, there may be no time for a sequential step-by-step process where deleting the phrase is appropriate and entities will need to trust that the TOP is making the correct decisions. If there is time, such as a pre-contingency forecast that an element may exceed a rating, but the contingency has not occurred, then a step-by-step sequential process where the TOP in an emergency state takes action first is more appropriate. How about something like: "provided that, time permitting, the requesting entity has implemented its comparable emergency procedures". Of course this introduces the difficult to measure "time permitting", but maybe this could be clarified as pre-contingency vs. post-contingency
Yes
Yes, it is appropriate to delete GOP from this requirement. However, consider adding a bullet under TOP-003-1 R1.1 that includes planned and unplanned generator capacity changes (which is then referred to in R4), similar to the current TOP-002-2, R14.1.
Yes
We assume "Yes" means we agree that a subset of SOLs should be reported. First, any voltage stability and transient stability limited SOLs should be reported. Second, for thermally limited SOLs, an equipment voltage class threshold for the facility with the thermal limit is probably the easiest to implement, e.g., > 200 kV, and seems consistent with other

standards with this threshold (e.g., PRC 023, FAC-003). We are a bit confused with handling of IROLs, IRO-009-1 seems to make the RC responsible for managing IROLs, and therefore, no reporting of IROLs seems to be needed in TOP-001-2; hence, should SOLs that are IROLs be reported? Note that there seems to be a conflict between this requirement and the requirements of IRO-009-1, e.g., both the TOP and the RC are being held accountable to managing IROLs. This arrangement seems fraught with potential for confusion. We believe only one entity ought to be responsible for managing IROLs, and that entity should probably be the RC. This comment applies to R6 of TOP 001 2, and this comment also applies to the conflict between TOP-004-3 R1 and IRO 009-1 R4, which assign the responsibility of operating within IROL limits to both the RC and TOP. Who has primary responsibility? Who takes leadership in a situation? Is RC primary with TOP back-up?
Yes
If the requirement is deleted, you might want to consider changing the time frame to include the Planning Horizon to clarify that operating procedures / agreements between utilities are required in the long term (e.g., interconnection agreements, etc.), as well as to align with FAC-002 and the TPL standards
Yes
We believe that such a provision is necessary to enable coordination of major maintenance outages to ensure resource adequacy for the region for generation related outages, and to ensure coordination of scheduled transmission outages in a localized area, for seasonal assessment purposes. There are probably two types of maintenance to be addressed, major maintenance schedules, and more minor maintenance due to equipment failure that does not cause an unscheduled outage. First, each region does seasonal assessments, it may be a good idea to tie major maintenance schedules as input into the region’s seasonal assessments, but allow flexibility in the actual schedules of these major maintenance schedules, with a reasonable input time frame to provide that input, e.g., two months before the start of the season. Second, there will always be unexpected maintenance schedules of shorter duration due to equipment failure that does not cause the facility to have an unscheduled outage, but, needs to be corrected. These are much more difficult to coordinate and schedule and may not allow a multi-day advance notice, so, maybe we could make the requirement only apply to major maintenance schedules.
Yes
We generally support the revised standards, but did have a few additional comments: • The data retention is significantly longer than earlier standards, e.g., three years rather than 3 months, and the data retention is not consistent between standards, e.g., TOP-001-2 is one year, TOP-002-3 is six months, TOP-003-1 and TOP-004-3. What is your reasoning behind these changes and the inconsistencies between them? Also, saving daily operating data for three years seems a long time. • TOP-002-3 R1 probably ought to refer to TOP-003-1 as one of the sources of data for the assessments. • Do the standards require current day plans? TOP-002-3 and IRO-004-1 only covers next day. Are we making current day equivalent to real-time, and therefore not requiring a plan for the current day? • TOP-002-3 R1 assigns the same task to the TOP that the RC has in IRO 004 1 R1, although not as confusing as real-time operations with two entities responsible for the same thing, as discussed above in the comments to TOP-001-2, this also has potential for confusion of roles, responsibilities and actions. Should only one entity be responsible for next day plans, e.g., the RC? Or is the distinction that RCs study interfaces, whereas the TOPs assess its entire system? If so, should such a distinction exist?
Individual
Gregory Campoli
New York Independent System Operator
Yes
No
We believe there are occasions when a GOP may need to take actions that would require coordination with or notification of the RC/TOP/BA or others who could be impacted. At this time it is not clear what other standards could obligate the GOP to do so if the GOP were removed from this requirement.
No
System Operating Limits are meant to “ensure operation within acceptable reliability criteria”. Understanding that there is a subset of more critical SOL’s defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances.
No
: No, this requirement should not be deleted. Agreements among TOPs are needed to ensure proper coordination of operational plans and actions. However, we do not agree that “switching of synchronous tie lines” should be specified in the requirement, nor should it be the only action specified in a TOP agreement as there are other items such as coordinating reactive power and voltage support, planned and forced outages, emergency operation, restoration, re-synchronization, etc. that need to be included in the agreement. We suggest this requirement be revised to: “Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specifies operation coordination among them.”
No
This should be handled on a local or regional basis. There is a wide diversity of systems in place with reporting

requirements defined, in some cases based in market requirements. It may not be reasonable to place the least common requirement on all entities in NERC.
No
We generally support the direction the SDT is moving but would require consideration of the comments provided in this transmittal. What is replacing TOP-001 R7? The requirement was previously TOP-008-R2, got moved to TOP-001 R7, but now both TOP-001 R7 is deleted and TOP-008 is deleted. Is there still going to be a requirement to use the most restrictive limit when multiple entities have different limits? TOP-003-1 makes reference to functional responsibilities and responsibilities per the NERC Functional Model. We do not agree with these references since it is unclear the status of the NERC Functional Model and how it relates to the NERC Standards. It has been noted that the NERC Functional Model is only for guidance and is not a standard. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some are designed to retain data for 90 days. The SDT should take into consideration the storage media. In some cases equipment is changed and the data may not be obtainable, or cost prohibited.
Individual
Alice Murdock
Xcel Energy
No
Yes
Yes
We agree R2 is not necessary and should be deleted. Additionally, the use of the term "Agreements" is concerning, especially when the additional language requires one to "specify switching".
Yes
Yes
In general, we appreciate the drafting team's work and feel the drafted standards are a positive move towards more simplified requirements. However, we do have some concerns, detailed below. TOP-001 >We feel the new R3 should also be applicable to BAs & GOs. >R4 - The phrase “reliability entities” needs definition. It is not clear who is being referenced. >R6 – consider adding language to include SOLs. TOP-002 >R1- We assume that the use of the defined term “Contingency” implies N-1 contingency planning. Yet, it is not clearly stated as such and therefore open to some interpretation. We recommend adding language to clarify, similar to the current version. >R2 – What is the intent here? Please clarify if planning is intended to entirely prevent the exceedence of an IROL, or to not exceed an IROL Tv. >R3 - The phrase “reliability entities” needs definition. It is not clear who is being referenced. >Deletion of the current R3 raises a concern as to what now requires LSEs and GOPs to coordinate their planning. This can present problems with TOPs and BAs attempting to collect needed data. >Deletion of current R8 – where is this covered elsewhere? TOP-003 >R1.1 “long term” needs more definition; we recommend changing to operating horizon >R1.1 We do not believe it was the drafting team’s intent to require outage reports of all BES components (breakers, etc), nor do we feel that is reasonable. We recommend the addition of a clarifying statement such as: “BES components specified by the Transmission Operator and Balancing Authority.” >R5 uses the phrase “immediate responsibility” – suggest changing this to “responsible for real time operations.” >It is not yet clear where the current R2 and R3 are being moved to. The previous draft indicated they would be moved to IRO standards. Please provide the link to those drafts or the project they are being worked under.
Individual
Kathleen Goodman
ISO New England Inc.
Yes
Yes
We believe this is covered by various other requirements in various other standards and need not be maintained here.
No
System Operating Limits are meant to “ensure operation within acceptable reliability criteria”. Understanding that there is a subset of more critical SOL’s defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances, either through SCADA or other means. This should ensure keeping an eye on SOLs so that cascading into an IROL will not occur.
Yes
We beleive this is sufficiently covered by the Standards in their totality.
No

While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region and, as such, notification requirements should be established within each region based on the needs of the RC. These may be dictated by an entities market structure, which should not be influenced by NERC Standards.
No
We disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time." SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability? Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? TOP-002-3 M1--Power flow study results will not be available for those days where studies are not required. Those days may be considered pre-studied or a normal "studied" state. How is this to be measured? TOP-002-3 R2, R3 – A plan should be required when the review warrants it and should include both IROL and SOL. In a normal state there may already be existing coordination between reliability entities with no need to re-communicate. TOP-003-1 R1: Reference to the Functional Model in the requirement may not be appropriate. This requirement may be clearer if the specific responsibilities are included. R1.1 "Long Term Outages" should be defined or clarified. What about other outages that are potentially impactive? In general, it is not clear that the data specification includes real time communications or operational planning requirements. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some voice recorders are designed to retain data for 90 days. Have data recordings stored longer than 90 days only if requested by the RC or TOP.
Individual
Armin Klusman
CenterPoint Energy
No
CenterPoint Energy does not see a reliability-related need to establish a continent-wide requirement that specifies the time frames for advance notification of planned outages. Such an approach does not appear practical considering the varying types of outages (circuit breakers, transformers, buses, and lines) and differing long-range and short-range scheduling time frames. As regional practices are already in place, CenterPoint Energy recommends outage scheduling time frames continue to be determined on a regional basis.
No
CenterPoint Energy believes reliability requirements should not include vague and unmeasurable, fill-in-the-blank provisions, like those shown in TOP-003 Requirement 1. R1 states "Each Transmission Operator and Balancing Authority shall have a documented specification for data required to fulfill their respective responsibilities per the NERC Functional Model." In addition, CenterPoint Energy disagrees with the accompaning TOP-003 Requirement 4 that requires numerous entities to comply with fill-in-the-blank provisions developed through R1. As written, R1 leaves it open to the whim of a Transmission Operator or Balancing Authority to conjure a list of required data, without any process for impacted entities to argue the reasonablesss of the data. In R1.1, the SDT has added two examples of required data by stating "Long term outages of Bulk Electric System equipment when they are known" and "Equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority". These vague examples leave it to the total discretion of a Transmission Operator or Balancing Authority. CenterPoint Energy recommends rewording Requirement 1 and deleting TOP-003 Requirement 4.
Group
MRO NERC Standards Review Subcommittee
Michael Brytowski
Yes
Yes
No
IROLs are a sufficient subset to report.
Yes

No
After the review of the paragraph 1612 of the FERC final order 693, the MRO NSRS would like them to be more specific about the type of outages and consistent with the Reliability Coordinator's requirement; the Reliability Coordinator has a wide-area view. How would this country-wide advance notice improve reliability for two independent systems not physically interconnected?
Yes
See response to question number 5 which is "After the review of the paragraph 1612 of the FERC final order 693, the MRO NSRS would like them to be more specific about the type of outages and consistent with the Reliability Coordinator's requirement; the Reliability Coordinator has a wide-area view. How would this country-wide advance notice improve reliability for two independent systems not physically interconnected?" In TOP-001-1 R1, what is a reliability directive? Should this be defined? The NERC standard COM-002-2 talks about the RC issuing a reliability directive, what is a directive? Not every communication is a directive; please clarify what is a reliability directive. Should each directive start off by stating that it's a directive and that 3 way communication should be used? (In the MISO Business Practice RTO-OP-002 R7, Telephone Communications Protocol, section 3.2.1, when issuing a Reliability Directive the following must be stated: "This is a Reliability Directive and I will need you to repeat it back.") Other MISO Business Practices which discuss reliability directives are RTO-BPM-006-R2 and RTO-EOP-003-R8. The current standard TOP-002-2a includes an interpretation of R11 stating among other things that a "unique" study is not needed for each operating day. The MRO NSRS recommends revising the TOP-002-3 R1 to include this interpretation. For the TOP-003-1 R1, "Each Transmission Operator and Balancing Authority shall have a documented specification for data to support its Real-time monitoring and reliability assessments required to fulfill their respective responsibilities per the NERC Functional Model.", the MRO NSRS believes that this phrase "NERC Functional Model" should be removed since it is unclear as it reads now and it should be replaced with "R1.1, R1.2, and R1.3".
Group
IRC Standards Review Committee
Ben Li
Yes
No
We believe there are occasions when a GOP may need to take actions that would require notification to the RC/TOP/BA or others who could be impacted. This is not following directives; it is for the GOP to make known to others of actions it will take that can have a reliability impact or affect others. If a predetermined list of actions to be communicated is established, then this requirement is not needed. At this time it is not clear what other standards provide this list which collectively obligates the GOP to notify parties that would be impacted. If the requirements for a GOP to communicate and coordinating actions such as removing AVR from service, derating real and reactive capabilities, removing units, protective relays, stabilizers, exciters, etc. out of service, are covered by other standards, then we do not disagree with the proposed deletion.
No
(Please note that CAISO abstained from the following comments) System Operating Limits are meant to ensure operation within acceptable reliability criteria. We understand that IROL is one subset of the SOL's but there is another subset of SOLs that either have special relevance to the TOP, or though not determined to be IROLs at the onset, would have an adverse impact on interconnected system reliability if their exceedances are not mitigated or are simply ignored. We believe the TOPs are in the best position to determine this subset, subject to the concurrence of its Reliability Coordinators.
No
(Note that CAISO abstained from the following comments) No, this requirement should not be deleted. Agreements among TOPs are needed to ensure proper coordination of operational plans and actions. However, we do not agree that "switching of synchronous tie lines" should be specified in the requirement, nor should it be the only action specified in a TOP agreement as there are other items such as coordinating reactive power and voltage support, planned and forced outages, emergency operation, restoration, re-synchronization, etc. that need to be included in the agreement. We suggest this requirement be revised to: "Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specifies operation coordination among them."
No
This should be handled on a local or regional basis. There is a wide diversity of systems in place with reporting requirements defined, in some cases based in market requirements. It may not be reasonable to place the least common requirement on all entities in NERC.
No
(1) We believe there is a fundamental principle that TOPs need to operate their systems within SOLs. We propose the SDT re-instate the deleted words from TOP-004 R1 that address SOLs. Recognizing that not all SOLs have an impact on interconnected system reliability if their exceedances are not mitigated within some target time period, we propose the SDT consider qualifying the SOLs which the TOP must operate within along the same line as we propose in our

comments under Q2, namely, the set to be identified by the TOP subject to its RC's concurrence. (Please note that ERCOT abstained from these comments) To more fully address the issue with some SOLs that do not have any reliability impacts, we propose the SDT consider revising the definition of SOL. This will eliminate the need for each TOP to identify this subset and obtain the RC's concurrence. (2) We generally support the direction the SDT is moving but would require consideration of the comments provided in this transmittal. What is replacing TOP-001 R7? The requirement was previously TOP-008-R2, got moved to TOP-001 R7, but now both TOP-001 R7 is deleted and TOP-008 is deleted. Is there still going to be a requirement to use the most restrictive limit when multiple entities have different limits? TOP-003-1 makes reference to functional responsibilities and responsibilities per the NERC Functional Model. We do not agree with these references since it is unclear the status of the NERC Functional Model and how it relates to the NERC Standards. It has been noted that the NERC Functional Model is only for guidance and is not a standard.
Individual
Catherine Koch
Puget Sound Energy
Yes
Yes
Yes
Interconnections or major paths as specified by the region only
Yes
Yes
Individual
Dan Rochester
Independent Electricity System Operator
Yes
This phrase pre-supposes that the assisting TOP will need to implement emergency procedures in order to assist the requesting TOP. This may not always be the case if the assisting TOP is willing and able to provide assistance without any detrimental impact to its own system. If such an arrangement were to be permitted, the details would be covered in Operating Agreements between the two entities. The SDT may therefore wish to consider catering for this and other possibilities by appending the clause "…subject to the provisions of operating agreements where established…"
No
TOP-001-2 R4, as written, stipulates the need for coordination of operations, i.e., coordination with or notification of the RCs/TOPs/BAs or others who could be impacted by the GOPs actions and operational plans. This is more than merely providing data, which is covered by TOP-003-1 R4. On the latter requirement (TOP-003-1, R4), we are unable to find an explanation for the addition of "….including, but not limited to:" and the bulleted items that follow. It suggests that only the listed information needs to be provided. Requirement R1.1 would serve the intended purpose by simply saying: "A list of required data to be exchanged." We suggest deleting the added wording and bullets.
No
System Operating Limits are meant to "ensure operation within acceptable reliability criteria". Understanding that there is a subset of more critical SOL's defined as IROLs, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances. Further, this question runs counter with the SDT's proposal/decision to remove the requirement for the TOP to operate within SOLs from TOP-004-2, R1, to which we expressed a strong disagreement when commenting on the last posting. If there is no requirement for the TOP to operate within SOLs, then what purpose would it serve for the TOP to report exceeding SOLs? Similarly, what purpose would TOP-002, R1 serve? We suggest the SDT to first establish a principle regarding the need to operate within SOLs, then consider the implication of removing such a requirement from TOP-004-2, R1, when assessing other related requirements such as reporting exceedance (TOP-001, R5), performing day ahead assessment (TOP-002, R1), and developing methodology to calculate SOLs (FAC-014), etc. Finally, if the industry wishes to reduce the potential number of reports, such as those instances in which the SOLs are temporarily exceeded (popping in and out), a time and/or a percentage of SOL threshold may be introduced to achieve this.
No
We agree that specificity language such as "specify switching of synchronous BES tie lines" does not need to be included in R2. However, Operating Agreements cover activities other than switching, such as emergency assistance, switching coordination and communication, voltage/VAR support, system restoration, synchronization, etc. We suggest keeping R2, revising it to eliminate any duplication with other requirements and defining the minimum elements that

should be included in the agreement.
Yes
While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region. Such notification requirements should be established within each region based on the needs of the RC. Our experience in handling short and long term planned outages informs us that the timing and duration of outages will determine the allocation of time and other resource to assess impacts of the outages on the system. For short duration outages, a short term assessment is usually adequate as system conditions and topology are more predictable. The longer the duration of a planned outage, the less predictable are the system conditions and the more likely that other transmission facilities will be out of service during that period.
No
We do not support the revised standards. Our biggest concern is the removal of the requirement for TOP to operate within SOLs as stated in our response to Q#3. As stated in our previous comments we are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time." SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state, even before IROL violations become evident. If such upper bounds are to be ignored to enhance operating flexibility, the BES would be very vulnerable to instability, uncontrolled separation, or cascading outages upon the occurrence of subsequent contingencies. The 2003 blackout started off with an SOL violation, and is a good example of how a "localized" problem can propagate thru the interconnected network to become a widespread reliability problem. Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? We are also very concerned that R1/R2 in TOP-002 requires the TOP to assess potential exceedence of IROLs only but not SOLs. We feel strongly that R2 in TOP-002 should be revised so that it includes as part of the requirement, preclusion of operating in excess of any SOLs. Further, we believe that all SOLs should be respected in the planning time-frame and in real time with the exception of low likelihood or rare circumstances. WE believe the SDT may have misinterpreted our previous comments. By “system voltage may be depressed” we were saying the voltage may be lower than normal, we did not explicit state or imply that the depressed voltage will cause a collapse which appeared was the basis of the SDT’s response that we were talking about IROL - a subset of SOL. The argument that the TOP is required to calculate SOL but does not need to operate within all the time seems irrational. Operating with SOL all the time and correct exceedance within some defined time period is necessary to ensure reliability. The examples/rationale cited in the question asked in the previous comment form: “The SDT felt that requiring a TOP to operate within all SOLs could effectively reduce the TOPs operational flexibility by eliminating the TOP’s ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time.” was but one such situation. Load shedding to reduce equipment loading is often regarded by TOPs as an exception, i.e., load is not shed to correct a temporary exceedance of equipment rating or a potential exceedance of applicable equipment rating if a contingency were to occur. The rationale is simply to not shed load if exceedance of the facility’s continuous rating is expected to be temporary, or if a contingency were to occur then the expected loading will exceed the concerned equipment’s applicable rating since we do not shed load pre-contingency to avoid shedding load after a contingency has occurred. Operating within an SOL w/o having to shed load under some circumstances is clearly conveyed in our comments (underlined in our comments above). However, without the fundamental requirement to operating within SOL, it opens the door to various kinds of unreliable operating conditions. A first overloaded line, which trips because it loading is not corrected, will cause loading on other lines to increase. There is no certainty as to when and where loading on the remaining system will cease to cause additional tripping. Also, the absence of such a requirement begs the question on the need to: (a) Calculate SOL (FAC-014) in the first place. The SDT’s response that FAC-014 also requires the TOP to “communicate your SOLs to other entities so that they can respect your operational limits” seems a bit unfair since the TOP, as the SOL developer, does not itself need to respect the SOL but others do. And who are these “other entities” within the TOP area that need to respect the SOLs - The BA, GOP or the RC, while the TOP has the transmission reliability authority within its area and takes primary responsibility in transmission reliability (other than the RC who has a wide-area view and has the final authority)? (b) Perform day ahead analysis (TOP-002, R1) without requiring any follow-on actions if the analysis shows that SOLs will be exceeded. Developing SOLs and assessing if they will be exceeded would simply be an academic exercise. We are unable to determine how will not respecting SOLs and not having follow-on actions when SOLs are assessed to be exceeded contribute to reliability? (c) Report exceedances and corrective actions taken (TOP-001, R5). This serves no purpose if a TOP is not required to operate within SOLs. (2) TOP-002, R1 requires a TOP to assess next day operations and identify if any SOLs will be exceeded, and the actions related to SOL stops there. It is irresponsible for the TOP to not do anything such as adjusting outage plans and/or requesting adjustment to resource plans to arrive at operating conditions that will no cause SOLs to be exceeded. A requirement similar to that of R2 (for the IROL) should be developed. The only difference between them would be the need to prepare for load shedding when mitigating measures run out. (3) We noted that some VSLs are graded according to the number of occurrences. Please refer to the recent posting on the revised VSLs for 8 sets of standards, in which the VSLSDT made reference to the June 2008 FERC Order on VSL. In the Order, FERC provided a guideline (among others) that VSLs should not be determined by the number of occurrence. Specifically, FERC’s Guideline #4 stipulates that: Guideline 4 — VSLs should be based on a single violation, not on a cumulative number of violations (unless stated otherwise in the requirement). We suggest the SDT to

revise these VSLs accordingly.
Individual
Jason Shaver
American Transmission Company
No
The Standard states that the TOP render emergency assistance as requested and available. There are other standards (EOP-001, EOP-005, EOP-008) that require an entity to implement its emergency procedures. If an entity does not implement emergency procedures when required it would be a violation. Adding a sentence here that requires the requesting entity to implement its comparable emergency procedures would be redundant to the other Standards.
No
This requirement does not get into the specifics of what is required of the GOP other than to state that it shall coordinate its operations, which is an important function. TOP-003-1 requires specificity regarding data exchange which is a different and more specific scope than TOP-001-2 R4. The two requirements are very different in scope and are, therefore, not redundant.
No
Again, TOP-001-3 requires general coordination vs. TOP-004-3 has a very specific requirement regarding agreements that specify switching of synchronous BES tie lines. The two requirements are different in scope and are, therefore, not redundant.
No
We support the revised Standards. However, the questions asked do not reflect the current redlined versions of the Standards. We should be commenting on the version of the Standard that the drafting team wants to move forward with. The comment form and questions should match the current redlined version and not ask questions related to a proposed changed version.
Individual
Michael Ayotte
ITC Transmission
No
Generators have an important role in supporting BES reliability and that should be recognized. Taking a unit offline, particularly a must-run unit, should be coordinated with the TOP.
At a minimum, the Transmission Operator should report any SOL that has exceeded or is expected to exceed 30 minutes.
Yes
We would rather see a requirement that the RC specify the time period requirements for planned outages. While not opposed to having a uniform time requirement, we are not sure if it is necessary. If a time period is to be developed, it should consider voltage level, in other words more lead time for higher voltages. In addition, RC specified planned outage time period requirements should apply to transmission and generation outages.

Consideration of Comments on Second Draft of Standards for Real-Time Operations (Project 2007-03)

The Real-time Operations Standard Drafting Team thanks all commenters who submitted comments on the Second Draft of Standards for Real-Time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from April 7, 2009 through May 8, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 37 sets of comments, including comments from more than 130 different people from over 45 companies representing all 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Due to industry comments, a need to ensure the VSLs conform to the latest set of VSL guidelines, and continuing to respond to Order 693 directives, the following items have been changed:

- TOP-001-2: R2, R3, R4, R5 (added), R6 (added), R7, M2, M5 (added) M6 (added), R1-R8 VSLs
- TOP-002-3: R1, R2, M1, R1-R3 VSLs
- TOP-003-1, R1, R1 bullet #1, R4, R5, M4, M5, data retention for R4 & R5, R1-R5 VSLs
- TOP-004-3: R1 (moved to TOP-001-2, R5), R2 (delete)

The RTO SDT supports the following definition of Reliability Directive drafted by the Reliability Coordination SDT and capitalized the use of this term in TOP-001-2, Requirement R1 and associated measure and violation severity levels. (Comments on the definition are being solicited by the RTO SDT.)

> **Reliability Directive:** A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency

Due to the number of changes, the SDT is recommending a third posting.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
2.	Group	Harry Tom	Project 2007-02 Operating Personnel Comm Protocols SDT	X	X			X				X	X

Group 1 additional members:

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Burns	Transmission Technical Operations	WECC	1
2. Tim Loepker	Dispatch	WECC	1

Group 2 additional members:

Additional Member	Additional Organization	Region	Segment Selection
1. Lloyd Snyder	GSOC	SERC	1
2. Tom Irvine	HydroOne	NPCC	1, 9
3. Leanne Harrison	PJM	RFC	2
4. James McGovern	ISO-NE	NPCC	2
5. Fred Waites	Southern Company	SERC	1
6. Harvie Beavers	Colmac Clarion/Piney Creek LP	RFC	5
7. Alan N. Allgower	ERCOT	ERCOT	10

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

8.	Mark L. Bradley	ITC	MRO	1
9.	Mike Brost	JEA	FRCC	1
10.	William D Ellard	CAISO	WECC	2
11.	Wayne Mitchell	Entergy	SERC	1
12.	John Stephens	City Utilities of Springfield	RFC	1
13.	Ronald Goins	MISO	MRO	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Frank Koza	Real Time Best Practices Standards Study Group	X	X	X	X	X		X	X		

	Additional Member	Additional Organization	Region	Segment Selection
1.	Sam Brattini	KEMA	NA - Not Applicable	NA
2.	Charles Jenkins	ONCOR	ERCOT	3, 5, 1
3.	Frank Koza	PJM	RFC	2
4.	Francis Esselman	American Transm Co.	RFC	1
5.	Doug Rempel	Manitoba Hydro	RFC	1, 3, 5
6.	Mike Oatts	Southern Company	SERC	3, 5, 1
7.	Patti Metro	NRECA	NA - Not Applicable	1, 4, 7
8.	Mike Schiavone	National Grid	NPCC	3, 5, 1
9.	Jack Kerr	Dominion	SERC	3, 5, 1
10.	James Vermillion	AECI	SERC	1, 3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Patrick Brown	PJM's NERC and Regional Coordination Department		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Albert DiCaprio	PJM	RFC	2
2.	Bill Harm	PJM	RFC	2
3.	Mark Kuras	PJM	RFC	2
4.	Tom Moleski	PJM	RFC	2
5.	Cathrine Wesley	PJM	RFC	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

Additional Member	Additional Organization	Region	Segment Selection
6. Susan McGill	PJM	RFC	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Jim Griffith	SERC OC Standards Review Group	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Phil Creech	Progress Energy Carolinas	SERC	1, 3, 5
2.	Paul Turner	Ga. System Operations Corp.	SERC	3
3.	Alisha Ankar	City of Springfield (CWLP)	SERC	1, 3, 5, 9
4.	Don Reichenbach	Duke Energy	SERC	1, 3, 5
5.	Jason Marshall	Midwest ISO	SERC	2
6.	Eugene Warnecke	Ameren	SERC	1, 3, 5
7.	Al McMeekin	SCE&G	SERC	1, 3, 5
8.	Vicky Budreau	Santee Cooper	SERC	1, 3, 5, 9
9.	Marc Butts	Southern Co Transmission	SERC	1, 3, 5
10.	Travis Sykes	TVA	SERC	1, 3, 5, 9
11.	Tim Hattaway	PowerSouth	SERC	1, 3, 5, 9
12.	Bob Thomas	IMEA	SERC	3, 5, 9
13.	Melinda Montgomery	Entergy	SERC	1, 3, 5
14.	Jim Case	Entergy	SERC	1, 3, 5
15.	Mike Clements	TVA	SERC	1, 3, 5, 9
16.	Steve Fritz	Aces Power Marketing	SERC	6
17.	Jalal Babik	Dominion Virginia Power	SERC	6
18.	Lee Taylor	Southern Co Transmission	RFC	1, 3, 5
19.	Mike Bryson	PJM	SERC	2
20.	John Troha	SERC Reliability Corp.	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dave Folk	FE	RFC	1
2. John Martinez	FE	RFC	1

		Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10
	3. Andy Hunter		FE	RFC					1				
	4. John Reed		FE	RFC					1				
	5. Steve Megay		FE	RFC					1				
	6. Larry Hartley		FE Solutions	RFC					5, 6				
7.	Group	Jalal Babik	Dominion Resources Inc.	X		X		X	X				
	Additional Member		Additional Organization	Region					Segment Selection				
	1. Jack Kerr		Electric Transmission	SERC					1				
	2. Louis Slade		Electric Market Policy	RFC					6				
	3. Mike Garton		Electric Market Policy	NPCC					5				
8.	Group	Guy Zito	Northeast Power Coordinating Council										X
	Additional Member		Additional Organization	Region					Segment Selection				
	1. Ralph Rufrano		New York Power Authority	NPCC					5				
	2. Al Adamson		New York State Reliability Council	NPCC					10				
	3. Greg Campoli		New York Independent System Operator	NPCC					2				
	4. Roger Champagne		Hydro-Quebec TransEnergie	NPCC					2				
	5. Kurtis Chong		Independent Electricity System Operator	NPCC					2				
	6. Sylvain Clermont		Hydro-Quebec TransEnergie	NPCC					1				
	7. Manuel Couto		National Grid	NPCC					1				
	8. Chris de Graffenried		Consolidated Edison Co. of New York, Inc.	NPCC					1				
	9. Brian Evans-Mongeon		Utility Services	NPCC					6				
	10. Mike Garton		Dominion Resources Services, Inc.	NPCC					5				
	11. Michael Gildea		Constellation Energy	NPCC					6				
	12. Brian Gooder		Ontario Power Generation Incorporated	NPCC					5				
	13. Kathleen Goodman		ISO - New England	NPCC					2				
	14. David Kiguel		Hydro One Networks Inc.	NPCC					1				
	15. Michael Lombardi		Northeast Utilities	NPCC					1				
	16. Randy MacDonald		New Brunswick System Operator	NPCC					2				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
	17. Bruce Metruck		New York Power Authority	NPCC					6				
	18. Robert Pellegrini		The United Illuminating Company	NPCC					1				
	19. Michael Schiavone		Nationa Grid	NPCC					1				
	20. Michael Sonnelitter		FPL Energy/NextEra Energy	NPCC					5				
	21. Peter Yost		Consolidated Edison Co. of New York, Inc.	NPCC					3				
	22. Gerry Dunbar		Northeast Power Coordinating Council	NPCC					10				
	23. Lee Pedowicz		Northeast Power Coordinating Council	NPCC					10				
9.	Group	Jason L. Marshall	Midwest ISO Stakeholders Standards Collaborators		X								
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Kirit Shah		Ameren	SERC					1				
10.	Group	Michael Brytowski	MRO NERC Standards Review Subcommittee										X
	Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
	1. Carol Gerou		MP	MRO					1, 3, 5, 6				
	2. Neal Balu		WPS	MRO					3, 4, 5, 6				
	3. Terry Bilke		MISO	MRO					2				
	4. Joe DePoorter		MGE	MRO					3, 4, 5, 6				
	5. Ken Goldsmith		ALTW	MRO					4				
	6. Jim Haigh		WAPA	MRO					1, 6				
	7. Terry Harbour		MEC	MRO					1, 3, 5, 6				
	8. Jospeph Knight		GRE	MRO					1, 3, 5, 6				
	9. Scott Nickels		RPU	MRO					3, 4, 5, 6				
	10. Dave Rudolph		BEPC	MRO					1, 3, 4, 6				
	11. Eric Ruskamp		LES	MRO					1, 3, 5, 6				
	12. Pam Sordet		XCEL	MRO					1, 3, 5, 6				
11.	Group	Ben Li	IRC Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Anita Lee	AESO	WECC	2
2. Steve Myers	ERCOT	ERCOT	2
3. Patrick Brown	PJM	RFC	2
4. Lourdes Estrada-Salinero	CAISO	WECC	2
5. Charles Yeung	SPP	SPP	2
6. James Castle	NYISO	NPCC	2
7. Matt Goldberg	ISO-NE	NPCC	2
8. Bill Phillips	MISO	MRO	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
12.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
13.	Individual	Hugh Francis	Southern Company	X		X		X	X				
14.	Individual	Mike Davis	WECC										X
15.	Individual	Frank Gaffney	FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool	X		X	X		X				
16.	Individual	Scott McGough	Oglethorpe Power Corporation					X					
17.	Individual	Chris Scanlon	Exelon	X		X		X	X				
18.	Individual	Michael J. Sonnelitter	NextEra Energy Resources, LLC					X					
19.	Individual	Harvie Beavers	Colmac Clarion					X					
20.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
21.	Individual	Jianmei Chai	Consumers Energy Company			X	X	X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
23.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
24.	Individual	Nied	Con Edison System Ops	X		X							
25.	Individual	Kasia Mihalchulk	Manitoba Hydro	X		X		X	X				
26.	Individual	Ed Davis	Entergy Services	X		X		X	X				
27.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
28.	Individual	Kirit Shah	Ameren	X		X		X	X				
29.	Individual	Tony Kroskey	Brazos Electric Power Cooperative, Inc.	X									
30.	Individual	Gregory Campoli	New York Independent System Operator		X								
31.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
32.	Individual	Kathleen Goodman	ISO New England Inc.		X								
33.	Individual	Armin Klusman	CenterPoint Energy	X									
34.	Individual	Catherine Koch	Puget Sound Energy	X									
35.	Individual	Dan Rochester	Independent Electricity System Operator		X								
36.	Individual	Jason Shaver	American Transmission Company	X									
37.	Individual	Michael Ayotte	ITC Transmission	X									

1. TOP-001-2, R3: Regarding the requirement to provide emergency assistance - The SDT deleted the phrase "provided that the requesting entity has implemented its comparable emergency procedures" from the first iteration of the revised standard. Based on comments received from the first posting, the SDT is considering reinstating this phrase. Do you agree that this phrase should be reinstated?

Summary Consideration:

The vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard. Therefore, even though the SDT does not find any technical merit in restoring the phrase, the phrase has been placed back in the requirement.

Due to industry comments, the SDT has modified the following requirement:

TOP-001-2, R3: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.

Organization	Yes or No	Question 1 Comment
Midwest ISO Stakeholders Standards Collaborators	No	When a compliance audit is conducted, the compliance auditor will not be evaluating a third party TOP to determine if they implemented all of their comparable procedures prior to requesting emergency assistance. They will simply review if the TOP being audited responded to the request for emergency assistance. If they did not, they are not necessarily in violation of the requirement because the requirement does recognize legal restrictions for not responding. Thus, if a third party TOP requested the audited TOP to shed load but had not done so themselves, the audited TOP may have appropriately and compliantly refused because their state laws and regulations prevent them from shedding load for neighbors unless they are doing the same.
American Transmission Company	No	The Standard states that the TOP render emergency assistance as requested and available. There are other standards (EOP-001, EOP-005, EOP-008) that require an entity to implement its emergency procedures. If an entity does not implement emergency procedures when required it would be a violation. Adding a sentence here that requires the requesting entity to implement its comparable emergency procedures would be redundant to the other Standards.
Oglethorpe Power Corporation	No	
Xcel Energy	No	
Response: The SDT discussed the comment and understands the issues being presented but the vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard and the SDT has done so.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">TOP-001-2, R3: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.</td></tr>
<tr><td>WECC</td><td>No</td><td>Leave phrase deleted and current red line indicates that this is only TO to TO assistance, we believe this is too restrictive and reinstate BA's and GO's.</td></tr>
<tr><td colspan="3">Response: The SDT discussed the comment and understands the issues being presented but the vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard and the SDT has done so. The Balancing Authority and Generator Operator must respond to reliability directives as per TOP-001-1, Requirement R1 so that assistance on a Balancing Authority –Transmission Operator or Generation Operator-Transmission Operator level is covered.
TOP-001-2, R3: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.</td></tr>
<tr><td>Entergy Services</td><td>No</td><td>There could be situations in which the TOP requesting support cannot implement comparable procedures. For instance, if reconfiguration from a neighboring system would resolve the situation, but reconfiguration on the requestor's system would not.</td></tr>
<tr><td colspan="3">Response: The SDT does not consider comparable procedures to be identical operating actions. The SDT discussed the comment and understands the issues being presented but the vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard and the SDT has done so.
TOP-001-2, R3: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.</td></tr>
<tr><td>Independent Electricity System Operator</td><td>Yes</td><td>This phrase pre-supposes that the assisting TOP will need to implement emergency procedures in order to assist the requesting TOP. This may not always be the case if the assisting TOP is willing and able to provide assistance without any detrimental impact to its own system. If such an arrangement were to be permitted, the details would be covered in Operating Agreements between the two entities. The SDT may therefore wish to consider catering for this and other possibilities by appending the clause subject to the provisions of operating agreements where established?</td></tr>
<tr><td>PJM's NERC and Regional Coordination Department</td><td>Yes</td><td>PJM supports the intent and the concept of comparability as intended by this requirement. However, PJM would note that TOP Emergency Procedures are not identical and are designed around the reliablity needs and capabilities of the individual TOP. When dealing with compliance, the interpretation of what is and what is not comparable could have unintended consequences.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
SERC OC Standards Review Group	Yes	Also, it is not clear in the context of TOP-001 what kinds of assistance an operator of transmission should give to another Transmission Operator (for example, refer to EOP-001, R1 for clarification)
FirstEnergy Corp	Yes	We support reinstating the proposed text and it should be clarified, provided that it can be shown that the action requested to assist the other party will mitigate an adverse reliability problem. FE suggests that the text should indicate provided that the requesting entity has implemented its comparable emergency procedures capable of lessening or mitigating the impact of the emergency and that the assistance requested will help to alleviate an adverse reliability problem.
Dominion Resources Inc.	Yes	As currently written an entity could be found non-compliant for not providing emergency assistance to a requesting entity that is not willing to help itself. That punishes the wrong party.
Northeast Power Coordinating Council	Yes	It is expected that further details of emergency assistance to be provided would be covered in Operating Agreements.
Southern Compnay	Yes	Yes, the phrase should be reinstated. Also, these actions should be coordinated by the Reliability Coordinator(s). Thus, we believe the verbiage should ultimately be: provided that the requesting entity has implemented its comparable emergency procedures as coordinated by the Reliability Coordinator(s).
FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool	Yes	This is a tough one to answer, there are conceivably two types of timelines for emergencies, e.g., an emergency where response is required within minutes vs. response during a longer period of time. If a response is needed in minutes, such as post-contingency with a facility within a 10 minute emergency rating, there may be no time for a sequential step-by-step process where deleting the phrase is appropriate and entities will need to trust that the TOP is making the correct decisions. If there is time, such as a pre-contingency forecast that an element may exceed a rating, but the contingency has not occurred, then a step-by-step sequential process where the TOP in an emergency state takes action first is more appropriate. How about something like: provided that, time permitting, the requesting entity has implemented its comparable emergency procedures. Of course this introduces the difficult to measure time permitting, but maybe this could be clarified as pre-contingency vs. post-contingency
American Electric Power	Yes	AEP would suggest that the phrase be reinstated with a change of the word implemented to taken into consideration. It is important that entities not solely rely on emergency assistance when alternatives may be available. The timing itself may necessitate alternative approaches.
Consumers Energy Company	Yes	An Entity can not be required to take actions for another if the requesting entity has not taken all steps available to them to correct the situation.

Organization	Yes or No	Question 1 Comment
Con Edison System Ops	Yes	I justify this by saying that this phrase should already included in an operating agreement between the TO's. ...but, having this wording in the standard as well will serve to ensure that TO's have their documents and agreements up to date.
Oncor Electric Delivery	Yes	This phrase should be reinstated.
Manitoba Hydro	Yes	
Duke Energy	Yes	
Ameren	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
New York Independent System Operator	Yes	
ISO New England Inc.	Yes	
Puget Sound Energy	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Subcommittee	Yes	
IRC Standards Review Committee	Yes	
PacifiCorp	Yes	
NextEra Energy	Yes	

Organization	Yes or No	Question 1 Comment
Resources, LLC		
Colmac Clarion	Yes	
E.ON U.S.	Yes	

Response: Thank you for your response. The vast majority of respondents are suggesting that the phrase be reinstated into the language of the standard and the SDT has done so.

> **TOP-001-2, R3**: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements.

2. **TOP-001-2, R4: Regarding the requirement to coordinate operations – Based on comments received from the first posting, the SDT is considering deleting the GOP from this requirement. Comments were received questioning the role of the GOP in reliability analysis beyond providing the data in TOP-003-1, Requirement R4. Do you agree that the GOP should be deleted from this requirement?**

Summary Consideration: There was no consensus on the removal of the Generator Operator; therefore, the SDT agrees to retain the Generator Operator in TOP-001-2, R4.

Organization	Yes or No	Question 2 Comment
FirstEnergy Corp	No	TOP-001-2 R4 requires the actions of the GOP be coordinated with impacted entities while TOP-003-1 R4 requires the GOP to provide data to the TOP and BAs. These are two completely different aspects of the BES operation and both need to be addressed by a standard.
Northeast Power Coordinating Council	No	We believe there are occasions when a GOP may need to take actions that would require coordination with or notification of the RC/TOP/BA or others who could be impacted. At this time it is not clear what other standards could obligate the GOP to do so if the GOP were removed from this requirement.
IRC Standards Review Committee	No	We believe there are occasions when a GOP may need to take actions that would require notification to the RC/TOP/BA or others who could be impacted. This is not following directives; it is for the GOP to make known to others of actions it will take that can have a reliability impact or affect others. If a predetermined list of actions to be communicated is established, then this requirement is not needed. At this time it is not clear what other standards provide this list which collectively obligates the GOP to notify parties that would be impacted. If the requirements for a GOP to communicate and coordinating actions such as removing AVR from service, derating real and reactive capabilities, removing units, protective relays, stabilizers, exciters, etc. out of service, are covered by other standards, then we do not disagree with the proposed deletion.
Southern Company	No	The GOP needs to communicate problems that could impact normal operation.
E.ON U.S.	No	The requirement should state that the Generator Operators should be required to coordinate with their respective TOP not simply provide data.
Entergy Services	No	The status of large generators can have a reliability impact on other reliability entities, and they should be included in this standard.
Duke Energy	No	We believe it’s critical for the GOP to coordinate operations with the TOP.

Organization	Yes or No	Question 2 Comment
Ameren	No	GOPs need to coordinate their activities. For instance, a small tube leak might not mandate an immediate outage for a plant electrically near a known SOL/IROL area. To the extent the GOP and TOP coordinate when the outage to repair this condition will occur, BES reliability benefits.
Brazos Electric Power Cooperative, Inc.	No	If a GOP is to comply with directives from a TOP in R1, then a requirement "to coordinate operations" is needed in R4.
New York Independent System Operator	No	We believe there are occasions when a GOP may need to take actions that would require coordination with or notification of the RC/TOP/BA or others who could be impacted. At this time it is not clear what other standards could obligate the GOP to do so if the GOP were removed from this requirement.
Con Edison System Ops	No	The GOP wording should remain.
Independent Electricity System Operator	No	TOP-001-2 R4, as written, stipulates the need for coordination of operations, i.e., coordination with or notification of the RCs/TOPs/BAs or others who could be impacted by the GOPs actions and operational plans. This is more than merely providing data, which is covered by TOP-003-1 R4.On the latter requirement (TOP-003-1, R4), we are unable to find an explanation for the addition of .including, but not limited to: and the bulleted items that follow. It suggests that only the listed information needs to be provided. Requirement R1.1 would serve the intended purpose by simply saying: A list of required data to be exchanged. We suggest deleting the added wording and bullets.
American Transmission Company	No	This requirement does not get into the specifics of what is required of the GOP other than to state that it shall coordinate its operations, which is an important function. TOP-003-1 requires specificity regarding data exchange which is a different and more specific scope than TOP-001-2 R4. The two requirements are very different in scope and are, therefore, not redundant.
Response: There was no consensus on the removal of the Generator Operator; therefore, the SDT agrees to retain the Generator Operator in TOP-001-2, R4.		
Midwest ISO Stakeholders Standards Collaborators	No	What if the unit is a reliability must run unit? With this requirement in place, the GOP may be more proactive in keeping the unit running (i.e. willing to take a greater risk damaging the unit if there is already a problem with the unit). Without the requirement, the GOP may shut the unit down at the first sign of any problem.
ITC Transmission	No	Generators have an important role in supporting BES reliability and that should be recognized. Taking a unit offline, particularly a must-run unit, should be coordinated with the TOP.
Response: The SDT has agreed to retain the Generator Operator. The SDT believes that the specific issue mentioned in your comments related to a reliability-		

Organization	Yes or No	Question 2 Comment
must-run generator's failure to coordinate operations is a contractual issue rather than a reliability issue.		
SERC OC Standards Review Group	No	
WECC	No	
Consumers Energy Company	No	
Response: Thank you for your response.		
PJM's NERC and Regional Coordination Department	Yes	The data obligations for GOPs to coordinate with its TOPs is covered in TOP-001-2 R1. The operational obligations for GOPs to coordinate with TOPs is covered in IRO-005. IRO-005-3 R1 places a requirement on the RC to have access to operating data (which specifically includes planned generation outages R 1.9). Thus the RC already has the responsibility to get the data in question. Given that the RC has the authority to request and obtain that data, one could argue that there is no need to also mandate that the GOP coordinate the same data, since that obligation already lies with the RC - see R4).
Dominion Resources Inc.	Yes	We support the change. FERC Codes/Standards of Conduct prohibit transfer of non-public transmission information to "marketing entities". Most staffs on the "transmission side" of the industry (TO, TOP, TP, RC) are reluctant to share any non-public information with those on the "generation side" (GO, GOP) because they are unsure whether or not those staffs are deemed "marketing entities".
FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool	Yes	Yes, it is appropriate to delete GOP from this requirement. However, consider adding a bullet under TOP-003-1 R1.1 that includes planned and unplanned generator capacity changes (which is then referred to in R4), similar to the current TOP-002-2, R14.1.
Colmac Clarion	Yes	Particularly since R2 contains no requirement for communications concerning notification of any problems or communication with the GOP. Likely the first time GOP will be aware of condition is at failure of RC/TO efforts to resolve same.

Organization	Yes or No	Question 2 Comment
American Electric Power	Yes	AEP appreciates the removal of redundant requirements, where possible to do so. We do not see the need for the GOP to be involved.
Oncor Electric Delivery	Yes	GOP should be deleted from this requirement.
ISO New England Inc.	Yes	We believe this is covered by various other requirements in various other standards and need not be maintained here.
Oglethorpe Power Corporation	Yes	
Exelon	Yes	
NextEra Energy Resources, LLC	Yes	
Manitoba Hydro	Yes	
Xcel Energy	Yes	
Puget Sound Energy	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Response: Thank you for your response. The SDT agreed to retain the Generator Operator as described in the summary response.		

3. TOP-001-2, R5: Regarding SOL exceedance notification – The consensus of the industry in the first posting was that some subset of SOLs needs to be reported but there was no clear cut agreement on what subset to report to the RC. The subset of SOLs to be reported must be easily identifiable and measurable while supporting reliability. Please remember in your response that as per the NERC Glossary that IROLs are a subset of SOLs. Given that requirement, what subset of SOLs do you feel need to be reported?

Summary Consideration: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has added TOP-001-1, Requirement R6 and modified TOP-001-1 Requirement R7 to require a subset of SOLs to be reported to the RC.

TOP-001-2, R6. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability.

TOP-001-2, R7. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	System Operating Limits are meant to ensure operation within acceptable reliability criteria. Understanding that there is a subset of more critical SOL's defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances which can be accomplished via SCADA or other means of action and communication when necessary.
ISO New England Inc.	No	System Operating Limits are meant to ensure operation within acceptable reliability criteria. Understanding that there is a subset of more critical SOL's defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances, either through SCADA or other means. This should ensure keeping an eye on SOLs so that cascading into an IROL will not occur.

Response: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has added TOP-001-1, Requirement R6 and modified TOP-001-1 Requirement R7 to require a subset of SOLs to be reported to the RC.

TOP-001-2, R6. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability.

TOP-001-2, R7. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.

There is nothing in the standard that precludes you from reporting all SOL exceedances to the Reliability Coordinator and SCADA may be used to accomplish this task but the SDT does not feel that it is either warranted to spell out a specific method or to report all SOLs.

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Subcommittee	No	IROLs are a sufficient subset to report.
Manitoba Hydro	No	IROL's only
IRC Standards Review Committee	No	(Please note that CAISO abstained from the following comments) System Operating Limits are meant to ensure operation within acceptable reliability criteria. We understand that IROL is one subset of the SOL's but there is another subset of SOLs that either have special relevance to the TOP, or though not determined to be IROLs at the onset, would have an adverse impact on interconnected system reliability if their exceedances are not mitigated or are simply ignored. We believe the TOPs are in the best position to determine this subset, subject to the concurrence of its Reliability Coordinators.
PacifiCorp	No	PacifiCorp has no specific subset of SOLs to suggest, however, they must be clear and easily identifiable and measurable. Suggested subsets should be included in the next comment phase for this SAR.
WECC	No	All SOL's should be reported to the RC
E.ON U.S.	No	All SOL exceedances on the BES should be reported to the RC and corrective actions should be coordinated with the RC.
New York Independent System Operator	No	System Operating Limits are meant to ensure operation within acceptable reliability criteria. Understanding that there is a subset of more critical SOL's defined by IROL, we suggest that the TOP should inform the RC of all SOLs and the actions being taken to address the exceedances.
Bonneville Power Administration		No preference, we report identified WECC rated paths.
NextEra Energy Resources, LLC		No comment.
PJM's NERC and Regional Coordination Department		PJM agrees that reporting should be based upon and restricted to reliability issues. Given the broad scope of the term SOL as defined in the NERC Glossary, PJM agrees that the requirement should be limited to a subset of the SOLsPJM proposes: 1. The TOP requirement on limit reporting parallel the RC requirement on IROLs 2. The TOP report violations (not exceedences) of any limit predefined by the TOP to be an essential limit (i.e. for a defined local condition that is deemed by the TOP to be of special concern and is not covered by any

Organization	Yes or No	Question 3 Comment
		predefined IROL). This approach provides a TOP the flexibility, when appropriate, to go beyond the definition of BES and to use reliability considerations rather than arbitary formulae to drive its operational reporting.
Midwest ISO Stakeholders Standards Collaborators		All SOL exceedances should be reported to the Reliability Coordinator. The Reliability Coordinator has the ultimate reliability authority. If the RC is not made aware of an SOL exceedance, how can the RC evaluate if the exceedance is actually approaching an IROL? Further, multiple SOL exceedances can be a sign of a greater reliability problem that the RC needs to rectify.
Southern Company		The subset will be pre-contingency IROL exceedences, post-contingency IROL exceedences, and real-time facilities experiencing SOL exceedences.
Con Edison System Ops		Let me start out by saying that ConEd reports all SOL's that occur on its system to the NYISO, our RC/BA/TOP.Only those SOL's should be reported to a higher authority (NPCC and above) that result from the TO operating its system in a state which is not allowed. That is, real time SOL's that arise from the TO operating its system on a post-contingency basis due to an exception granted by its RC should not be reported.
Entergy Services		Instances where an IROL is exceeded should be required to be reported to the RC. It should be left to the RC and TOP to agree to other SOLs that are important enough to be required to be reported to the RC.
ITC Transmission		At a minimum, the Transmission Operator should report any SOL that has exceeded or is expected to exceed 30 minutes.
SERC OC Standards Review Group	Yes	The subset of SOLs, other than IROLs (which must be reported), should be agreed upon between each Reliability Coordinator and the TOPs within the RCs reliability area.
FirstEnergy Corp	Yes	The question as written does not lend itself to a yes/no answer, the selection of yes was made to indicate that we agree some subset of SOL, when exceeded, warrants the a TOP notification to the RC. FE believes that the appropriate subset are those SOLs that are associated with a previously defined Interconnection Reliability Operating Limit (IROL) as determined via the FAC-014 reliability standard.
Dominion Resources Inc.	Yes	In addition to IROLs, the subset of SOLs that need to be reported should include any other SOL exceedances that the RC requests notification of and, in the Eastern Interconnection, any other SOL exceedances associated with permanent, reliability flowgates as defined in the NERC Book of Flowgates.
FMPA and its All Requirements Project Participants, as follows:	Yes	We assume “Yes” means we agree that a subset of SOLs should be reported. First, any voltage stability and transient stability limited SOLs should be reported. Second, for thermally limited SOLs, an equipment voltage

Organization	Yes or No	Question 3 Comment
Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool		class threshold for the facility with the thermal limit is probably the easiest to implement, e.g., > 200 kV, and seems consistent with other standards with this threshold (e.g., PRC 023, FAC-003). We are a bit confused with handling of IROLs, IRO-009-1 seems to make the RC responsible for managing IROLs, and therefore, no reporting of IROLs seems to be needed in TOP-001-2; hence, should SOLs that are IROLs be reported?Note that there seems to be a conflict between this requirement and the requirements of IRO-009-1, e.g., both the TOP and the RC are being held accountable to managing IROLs. This arrangement seems fraught with potential for confusion. We believe only one entity ought to be responsible for managing IROLs, and that entity should probably be the RC. This comment applies to R6 of TOP 001 2, and this comment also applies to the conflict between TOP-004-3 R1 and IRO 009-1 R4, which assign the responsibility of operating within IROL limits to both the RC and TOP. Who has primary responsibility? Who takes leadership in a situation? Is RC primary with TOP back-up?
American Electric Power	Yes	While it is expected that the Transmission Operators work in conjunction with the Reliability Coordinators to mitigate most SOL violations, a NERC requirement to report all SOL violations seems impractical. The IROLs provide a clear and logical subset of SOLs that should be reported to the RC.
Oncor Electric Delivery	Yes	Comments: Report all SOLs that require firm load to be dropped to return transmission elements within limits.
Duke Energy	Yes	Given that geography varies, system interdependencies and ratings philosophy, TOP/RC should agree on what to report.
Brazos Electric Power Cooperative, Inc.	Yes	The IROL subset needs to be reported.
Puget Sound Energy	Yes	Interconnections or major paths as specified by the region only
Response: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has added TOP-001-1, Requirement R6 and modified TOP-001-1 Requirement R7 to require a subset of SOLs to be reported to the RC. **TOP-001-2, R6**. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability. **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.		
Independent Electricity System Operator	No	System Operating Limits are meant to ensure operation within acceptable reliability criteria. Understanding that there is a subset of more critical SOL's defined as IROLs, we suggest that the TOP should inform the RC of all

Organization	Yes or No	Question 3 Comment
		SOLs and the actions being taken to address the exceedances.Further, this question runs counter with the SDT's proposal/decision to remove the requirement for the TOP to operate within SOLs from TOP-004-2, R1, to which we expressed a strong disagreement when commenting on the last posting. If there is no requirement for the TOP to operate within SOLs, then what purpose would it serve for the TOP to report exceeding SOLs? Similarly, what purpose would TOP-002, R1 serve? We suggest the SDT to first establish a principle regarding the need to operate within SOLs, then consider the implication of removing such a requirement from TOP-004-2, R1, when assessing other related requirements such as reporting exceedance (TOP-001, R5), performing day ahead assessment (TOP-002, R1), and developing methodology to calculate SOLs (FAC-014), etc. Finally, if the industry wishes to reduce the potential number of reports, such as those instances in which the SOLs are temporarily exceeded (popping in and out), a time and/or a percentage of SOL threshold may be introduced to achieve this.
Response: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has added TOP-001-1, Requirement R6 and modified TOP-001-1 Requirement R7 to require a subset of SOLs to be reported to the RC. **TOP-001-2, R6**. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability. **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded. The SDT does not plan to reintroduce a requirement to operate within all SOLs. The SDT believes that the true reliability requirement is to operate within IROLs and that non-IROL SOLs are a local operating issue. Further, no other commenters have expressed this concern.		
Colmac Clarion	Yes	Assume this is System Operating Limit and Interconnect Reliability Operating Limit (need to cite for first time acronym use as was done with 'BES' in purpose statement). Unsure of exact setpoint of reporting, but would likely be at anytime load approaches or exceeds planned or immediately available generation; perhaps within 2-5% greater then parity.
Response: The majority of responses indicate that some subset of SOL violations should be reported but that not all SOL violations should be reported. Given the majority position stated by industry, the SDT has modified Requirement R7 to require a subset of SOLs to be reported to the RC. To satisfy the concerns expressed by the minority, the SDT will make that subset of SOLs include the any non-IROL SOLs that the RC identifies as required to be reported to it. The requirement will further specify that this communication may be accomplished through SCADA to reduce communication burdens. **TOP-001-2, R6**. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability. **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.		

Organization	Yes or No	Question 3 Comment
The drafting team added the full term, “System Operating Limits” as suggested.		
Ameren	Yes	
Response: Thank you for your response.		

4. TOP-004-3, R2: Regarding Agreements on switching – Based on comments received from the first posting, the SDT is considering deleting this requirement. TOP-001-3, Requirement R4 already requires coordination of operations. Given that requirement, is TOP-004-3, Requirement R2 still necessary? Do you agree that TOP-004-3, Requirement R2 can be deleted?

Summary Consideration: The requirements of Reliability Standards should specify "What" is to be done to ensure reliability. The SDT feels that operating agreements may be one example of "How" Reliability Entities work to coordinate operations, but does not feel Reliability Standards should restrict the industry participants with regard to the various methods that may be used to ensure coordination is effected. The majority of respondents agree with this position and that the requirement should be deleted. In the next posting, TOP-004-3, Requirement R2 will be deleted.

In addition, since there would only be one requirement left in TOP-004-3, Requirement R1 has been moved to TOP-001-2, Requirement R5.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	Operating Agreements cover activities other than switching. We believe the requirement should be retained but any duplication eliminated.
Response: The SDT agrees that agreements may cover activities other than switching. The requirements of Reliability Standards should specify "What" is to be done to ensure reliability. The SDT feels that operating agreements may be one example of "How" Reliability Entities work to coordinate operations, but does not feel Reliability Standards should restrict the industry participants with regard to the various methods that may be used to ensure coordination is effected.		
IRC Standards Review Committee	No	(Note that CAISO abstained from the following comments)No, this requirement should not be deleted. Agreements among TOPs are needed to ensure proper coordination of operational plans and actions. However, we do not agree that "switching of synchronous tie lines" should be specified in the requirement, nor should it be the only action specified in a TOP agreement as there are other items such as coordinating reactive power and voltage support, planned and forced outages, emergency operation, restoration, re-synchronization, etc. that need to be included in the agreement. We suggest this requirement be revised to: "Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specifies operation coordination among them."
Response: The SDT believes you have hit upon precisely the concern it has. The proposed TOP-001-2, Requirement R4 requires coordination of operations with other Reliability Entities when operations are known or expected to have a reliability impact upon other Reliability Entities. The SDT recognizes that having an agreement in place specifying switching of synchronous BES tie lines, per the content of TOP-004-3, Requirement R2 is a subject that rightfully should be included with the coordination that is required by TOP-001-2, Requirement R4. Conversely, the full coordination of operations cannot be included within the more narrowly defined scope of coverage of TOP-004-3, Requirement R2. Further the SDT recognizes that the scope and number of individual agreements, which may be needed to ensure that all operations are fully coordinated for all operations known or expected to have a reliability impact upon other Reliability Entities is highly likely to vary greatly from region to region or organizational arrangement to organizational arrangement. Thus, the SDT does not feel it is appropriate, nor even feasible, to try to list in the Reliability Standards all the individual types of agreements which may be required. "What" is needed is a requirement that all Reliability Entities properly		

Organization	Yes or No	Question 4 Comment
and adequately coordinate operations with other reliability entities. Having agreements of various types may be one example of "How" that coordination is put into place.		
WECC	No	We believe there is a need for clear agreements
Ameren	No	Agreements (formal or informal) are necessary to describe the conditions under which the coordinated switching in TOP-001 takes place. It will be impossible for Transmission Planners to properly analyze the conditions that can be expected if there are no "rules" for operation.
Brazos Electric Power Cooperative, Inc.	No	Either leave TOP-004-3, R2 as is or move a requirement for an Agreement into TOP-001-3, R4.
Response: The SDT cannot disagree that agreements may be appropriate, depending upon the relevant regional requirements and organizational arrangements. However, the SDT believes that "What" is required is coordination of operations. The SDT further believes that agreements may be an example of "How" coordination is accomplished, but not necessarily the only way.		
New York Independent System Operator	No	No, this requirement should not be deleted. Agreements among TOPs are needed to ensure proper coordination of operational plans and actions. However, we do not agree that switching of synchronous tie lines should be specified in the requirement, nor should it be the only action specified in a TOP agreement as there are other items such as coordinating reactive power and voltage support, planned and forced outages, emergency operation, restoration, re-synchronization, etc. that need to be included in the agreement. We suggest this requirement be revised to: Each Transmission Operator shall have Agreements with directly interconnected Transmission Operators that specifies operation coordination among them.
Response: The SDT agrees with you that switching should not be the only action specified for agreement. The SDT cannot disagree that agreements may be appropriate, depending upon the relevant regional requirements and organizational arrangements. However, the SDT believes that "What" is required is coordination of operations. The SDT further believes that agreements may be an example of "How" coordination is accomplished, but not necessarily the only way. The SDT does not believe it is possible to list all the possible ways of "How" a requirement may be met.		
Independent Electricity System Operator	No	We agree that specificity language such as specify switching of synchronous BES tie lines does not need to be included in R2. However, Operating Agreements cover activities other than switching, such as emergency assistance, switching coordination and communication, voltage/VAR support, system restoration, synchronization, etc. We suggest keeping R2, revising it to eliminate any duplication with other requirements and defining the minimum elements that should be included in the agreement.
Response: The SDT agrees with you that switching should not be the only action specified for agreement. The SDT cannot disagree that agreements may be		

Organization	Yes or No	Question 4 Comment
appropriate, depending upon the relevant regional requirements and organizational arrangements. However, the SDT believes that "What" is required is coordination of operations. The SDT further believes that agreements may be an example of "How" coordination is accomplished, but not necessarily the only way. The SDT does not believe it is possible to list all the possible ways of "How" a requirement may be met. The SDT does not believe that an agreement necessarily equates to coordination, although, depending upon organizational arrangements and relationships, agreements may be an appropriate part of "How" coordination is effected.		
American Transmission Company	No	Again, TOP-001-3 requires general coordination vs. TOP-004-3 has a very specific requirement regarding agreements that specify switching of synchronous BES tie lines. The two requirements are different in scope and are, therefore, not redundant.
Response: The SDT agrees that an agreement and coordination differ in scope. Whereas coordination is "What" is required to ensure reliability, an agreement may be part of "How" coordination is effected.		
SERC OC Standards Review Group	Yes	If the SDT agrees with deleting R2, we suggest that R1 should be included in TOP-002 and TOP-004-3 retired.
FirstEnergy Corp	Yes	Yes, we agree with the recommendation to delete TOP-004-4 R2. Since this change would leave only one requirement within the TOP-004-4 standard, we urge the team to consider incorporating the requirement into another standard. One suggestion is consider adding the requirement to standard IRO-005-3 titled "Reliability Coordination - Current Day Operations". This could be added as a new requirement of IRO-005-3 or possibly a sub-requirement of requirement R11 of the IRO-005-3 standard. Alternatively, the requirement could be placed into the TOP-001 standard.
Response: The SDT agrees and has moved TOP-004-3, R1 to TOP-001-2, R5.		
FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool	Yes	If the requirement is deleted, you might want to consider changing the time frame to include the Planning Horizon to clarify that operating procedures / agreements between utilities are required in the long term (e.g., interconnection agreements, etc.), as well as to align with FAC-002 and the TPL standards
Response: Since switching of synchronous BES tie lines is an operations activity that may be included in the higher level "operations known or expected to have a reliability impact on other reliability entities", the SDT believes that the proposed Time Horizons proposed are appropriate. The Planning Horizon is applicable to activities more than one year in the future, and, therefore switching activities are not expected to have a reliability impact upon other entities in that Time Horizon. No change made.		
Exelon	Yes	Is there a typo in the question? TOP-001 does not have a rev 3. Assuming the intent is to refer to TOP-001-2,

Organization	Yes or No	Question 4 Comment
		R4 we agree.
American Electric Power	Yes	Please note the typographical error in question 4. TOP-001-3 in question 4 should read TPO-001-2.
Response: You are correct – the reference should have been TOP-001-2.		
Dominion Resources Inc.	Yes	It is not clear what an agreement between TOPs to "specify switching" of tie lines is supposed to be. If it is supposed to be an interconnection agreement, those are usually between Transmission Owners. Requirement R2 can be deleted.
Xcel Energy	Yes	We agree R2 is not necessary and should be deleted. Additionally, the use of the term "Agreements" is concerning, especially when the additional language requires one to "specify switching".
Midwest ISO Stakeholders Standards Collaborators	Yes	
MRO NERC Standards Review Subcommittee	Yes	
PacifiCorp	Yes	
Southern Company	Yes	Redundant requirements in separate standards are both confusing and waste resources.
NextEra Energy Resources, LLC	Yes	
Colmac Clarion	Yes	
E.ON U.S.	Yes	
Con Edison System Ops	Yes	It should be deleted. I see no need for keeping the R2 wording in there. It's confusing and leaves too much up to interpretation. As stated above, the "coordination of operations" wording in R4 would suffice.
Manitoba Hydro	Yes	
Entergy Services	Yes	

Organization	Yes or No	Question 4 Comment
Duke Energy	Yes	
ISO New England Inc.	Yes	We beleive this is sufficiently covered by the Standards in their totality.
Puget Sound Energy	Yes	
ITC Transmission	Yes	
Bonneville Power Administration	Yes	
PJM's NERC and Regional Coordination Department	Yes	PJM agrees that there is no need to include a requirement that focuses on switching procedures.
Response: The SDT thanks you for your support.		

5. The RTO SDT is attempting to respond to a directive in FERC Order 693 where a specific country-wide advance notice time period for planned outage notification would be established. Prior to writing such a requirement, the RTO SDT is polling the industry to see if it is needed and what the time period would be. Please indicate if you agree with such a provision. If you agree then please provide a number of days that you would consider appropriate for such advance notice, e.g., 7 days. If you disagree, then please state specific reasons for your disagreement.

Summary Consideration: Order 693, paragraph 1621 stated: "We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages." The SDT posed this question as a fact finding exercise in order to assist them in making a decision on how to respond to the FERC directive. In that regard, the SDT thanks all those who took the time and effort to explain their reasoning as part of their comments. The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions.

After reviewing the industry comments, the SDT concluded that TOP-001-1, Requirement R4 adequately covers this issue. The SDT bases this position on the requirement which includes the Operations Planning Time Horizon that covers the period from one day to one year. The requirement mandates that all plans are coordinated. The SDT interprets this to include planned outages when they are known.

Therefore, the SDT will not be drafting an additional requirement for a national standard advance notice time period for planned outage notification.

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
PJM's NERC and Regional Coordination Department	No	A mandated common time-period would likely conflict with some already FERC-approved procedures. Moreover, a common timing requirement will likely as reduce the benefits and flexibility of some procedures, as it would provide benefits to others.
Consumers Energy Company	No	Communication of planned or scheduled outages should take place in the planning phase. Communication should be as early in the phase as possible for all TOs GOs and BAs effected by the outage. To have a nationwide standard is too confining and removes possible flexibility that can come from open communication. TOP-003-0 requires communication of outage information on a daily basis.
SERC OC Standards Review Group	No	A time limit does not need to be established. Entities need to be able to plan short term outages, both transmission and generation when conditions permit in order to minimize impacts to the reliability of the system. For example, a transmission line in need of maintenance might only be available upon the outage (forced or planned) on a particular generator. With a standard in place, this opportunity would be missed. Delaying maintenance on a transmission line puts it at a greater risk of a forced outage.

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
FirstEnergy Corp	No	We do not believe there is a reliability need to establish a common industry wide lead-time for planned BES facility outages. It should be left to the RC and the applicable entities that it monitors (TOPs, GOPs) to establish agreed upon outage coordination procedures. In fact, it should not be expected that a minimum lead-time must always be rigidly adhered to. Consider that many transmission lines can only be taken out of service during a generator outage. If generator unit experienced a forced outage that would permit certain transmission lines to be maintained, such maintenance should not be delayed to simply adhere to a specific lead-time requirement. The RC's and their monitored entities should be given the flexibility to develop a process that is suitable to meet their needs.
Dominion Resources Inc.	No	(including # of days if appropriate): We don't recommend a country-wide advance notice. However, we agree that it is within the purview of the Reliability Coordinators to reach agreement with the applicable entity and set outage reporting requirements to meet their reliability assessment needs without the development of a new NERC reliability standard.
Northeast Power Coordinating Council	No	While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region. Such notification requirements should be established within each region based on the needs of the RC.
Midwest ISO Stakeholders Standards Collaborators	No	We do not believe there is a reliability need to establish an industry wide advance notification procedure for transmission outages. We believe that the need for advance notification of transmission outages should be identified completely between the TOP and RC in their outage coordination procedures. In fact, we believe such a requirement could actually be a detriment to reliability. Consider that many transmission lines can only be taken out of service during a generator outage. If the generator were to trip, the transmission line could not be taken out of service for lack of sufficient advance notice delaying the maintenance of the line and, thus, increasing the potential for the line to be forced out. It is not clear what reliability benefit could even be achieved by having an industry wide advance notification requirement. We believe that should such a requirement become a reality, there will be further reliability detriment as TO/TOPs delay maintenance in a struggle to transition to comply with such a requirement.
MRO NERC Standards Review Subcommittee	No	After the review of the paragraph 1612 of the FERC final order 693, the MRO NSRS would like them to be more specific about the type of outages and consistent with the Reliability Coordinator's requirement; the Reliability Coordinator has a wide-area view. How would this country-wide advance notice improve reliability for two independent systems not physically interconnected?
IRC Standards Review Committee	No	This should be handled on a local or regional basis. There is a wide diversity of systems in place with reporting requirements defined, in some cases based in market requirements. It may not be reasonable to place the least common requirement on all entities in NERC.
Southern Compnay	No	No time limit needs to be established. Entities need to be able to plan short term outages, generation and transmission.

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
		The Eastern Interconnection presently has an advanced outage notification through the NERC SDX.
American Electric Power	No	The current rules for each region are followed today and coordination is done very well. Seams agreements address the coordination across regions. Therefore, a country-wide period is not necessary from a reliability perspective. If it is otherwise determined to be necessary, AEP believes that it should be done at the IROL level since, by definition, these are the situations with wide area impact.
E.ON U.S.	No	The RCs already have advance notification requirements which TOPs must follow. Most BES facilities have limited impact on neighboring systems. Depending on the level of notification, this could impose an undue burden on Transmisson Operators and field switching personnel in performing needed maintenance. The Regions should identify a subset of facilities (similar to the ECAR Facility Outage Notification Table) subject to advanced notification requirements. Should a country-wide advance notice time period be established it should only apply to 200kV and above.
Oncor Electric Delivery	No	Comments (including # of days if appropriate): Oncor Electric Delivery does not believe a country-wide notification period is necessary. As each interconnection has it's unique characteristics, there is no assurance that a common advance notification period would work for all. Additionally, setting a common date within a NERC standard seems inconsistent with the intent of reliability based standards. Advanced notification seems to be more of a market function and is not reliability based.
Manitoba Hydro	No	We do not believe there is a reliability need to establish an industry wide advance notification procedure for transmission outages. We believe that the need for advance notification of transmission outages should be identified completely between the TOP and RC in their outage coordination procedures.
Entergy Services	No	There are processes already in place to ensure that outages are coordinated between affected systems. Creating a nation-wide requirement to set an advance notice time is not in the best interests of reliability. Rather flexibility should be allowed to coordinate and agree upon required maintenance activities that are necessary to ensure continued reliability.
Duke Energy	No	This comment form is not the right place to address this issue. We would have significant concerns with the idea too much to support a requirement that hasn't been drafted yet. Existing processes are in place between neighboring entities to exchange this type of information.
Ameren	No	First, the definition of planned outage is anything but an industry standard. So the rules around timing are putting the cart before the horse, And, anything in days is not practical given the need to get to short-term planned maintenance and the impacts of weather and forced outages on these planned outages. If a notification time is absolutely deemed necessary, 30 minutes to 1 hour would be workable under a mandatory, enforceable NERC standard framework.

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
Brazos Electric Power Cooperative, Inc.	No	At this time I see no reliability benefit for this requirement.
New York Independent System Operator	No	This should be handled on a local or regional basis. There is a wide diversity of systems in place with reporting requirements defined, in some cases based in market requirements. It may not be reasonable to place the least common requirement on all entities in NERC.
ISO New England Inc.	No	While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region and, as such, notification requirements should be established within each region based on the needs of the RC. These may be dictated by an entities market structure, which should not be influenced by NERC Standards.
CenterPoint Energy	No	CenterPoint Energy does not see a reliability-related need to establish a continent-wide requirement that specifies the time frames for advance notification of planned outages. Such an approach does not appear practical considering the varying types of outages (circuit breakers, transformers, buses, and lines) and differing long-range and short-range scheduling time frames. As regional practices are already in place, CenterPoint Energy recommends outage scheduling time frames continue to be determined on a regional basis.
Con Edison System Ops		Unless the piece of equipment is in a direct neighboring system, what utility would this offer to a TO? "Operations are already coordinated" amongst neighboring TO's with regard to tie-lines. It would not offer much in the way of information on how we operate our system.However, ConEd already sends notification of all of its approved outages on the Bulk Electric System to the NYISO via email automatically. So, I dont think it would be difficult to do if someone decides that they want 7 or 10 day notifiation on something. If this requirement came into being, the NYISO could then disburse COnEd's outage info to NPCC and rest of the East.A hard-line 7 or 10 day rule will be tough to enforce though. Many outages get approved much closer to the actual date...many within 2 days of the start.
ITC Transmission		We would rather see a requirement that the RC specify the time period requirements for planned outages. While not opposed to having a uniform time requirement, we are not sure if it is necessary. If a time period is to be developed, it should consider voltage level, in other words more lead time for higher voltages. In addition, RC specified planned outage time period requirements should apply to transmission and generation outages.
WECC	Yes	We believe outage notification to the RC for all equipment 100kV and above, and all generator outges of 50MW and above should be a mininum of 96 hours notice in advance.
FMPA and its All Requirements Project Participants, as follows:	Yes	We believe that such a provision is necessary to enable coordination of major maintenance outages to ensure resource adequacy for the region for generation related outages, and to ensure coordination of scheduled transmission outages in a localized area, for seasonal assessment purposes. There are probably two types of maintenance to be addressed,

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool		major maintenance schedules, and more minor maintenance due to equipment failure that does not cause an unscheduled outage. First, each region does seasonal assessments, it may be a good idea to tie major maintenance schedules as input into the region's seasonal assessments, but allow flexibility in the actual schedules of these major maintenance schedules, with a reasonable input time frame to provide that input, e.g., two months before the start of the season. Second, there will always be unexpected maintenance schedules of shorter duration due to equipment failure that does not cause the facility to have an unscheduled outage, but, needs to be corrected. These are much more difficult to coordinate and schedule and may not allow a multi-day advance notice, so, maybe we could make the requirement only apply to major maintenance schedules.
Exelon	Yes	Follow existing Guidelines, GADS states "well in advance" as notification for "Planned" outages. This typically means more than 30 days in advance. PJM uses the 30 day definition for "Planned". Nuclear / INPO uses 28 days (4 weeks) from an INPO definition for "Planned". 30 days seems to be a reasonable requirement.
Colmac Clarion	Yes	Current policy under some existing contract operators requires initial notification on a rolling 3 year plan and additional notification to 'dispatcher' at 30 days. Generally, verbal notification is also conducted between generating facilities and Transmission operator on a much shorter and timely basis additionally. Transmission/Distribution company has a similar long range, and short notification cycle.
Independent Electricity System Operator	Yes	While we agree in principle with this proposal, it must be recognized that factors affecting equipment outages vary from region to region. Such notification requirements should be established within each region based on the needs of the RC. Our experience in handling short and long term planned outages informs us that the timing and duration of outages will determine the allocation of time and other resource to assess impacts of the outages on the system. For short duration outages, a short term assessment is usually adequate as system conditions and topology are more predictable. The longer the duration of a planned outage, the less predictable are the system conditions and the more likely that other transmission facilities will be out of service during that period.
PacifiCorp	Yes	The appropriate number of days should be established on a region-wide basis, not a country wide basis. Each region has unique infrastructure that requires specific advance notice.
Bonneville Power Administration	Yes	No preference.
NextEra Energy Resources, LLC		No comment.
Xcel Energy	Yes	

Organization	Yes or No	Question 5 Comment (including # of days if appropriate):
Response: Thank you for your response. Please see the summary response for details.		

6. Do you generally support the revised standards? If your response is 'No', please explain your single biggest concern with the revised standards, including which specific requirement or set of requirements causes you the most concern and why.

Summary Consideration: Due to industry comments the SDT changed the following:

TOP-001-2, R2. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions.

TOP-001-2, R4. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected by the Transmission Operator to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. Such operations include, but are not limited to, relay or equipment failures and changes in generation, Transmission, Load, or operating conditions.

TOP-001-2, R6. Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs) which, while not IROLs, support its local area reliability.

TOP-001-2, R7.Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded.

TOP-001-2, R2 VSL	The Transmission Operator did not inform one affected Transmission Operator of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform two affected Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform three affected Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or anticipated Emergency conditions. OR The Transmission Operator did not inform four or more affected Transmission Operators of actual Emergency and anticipated Emergency conditions.

TOP-001-2, R6 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL which, while not an IROL, supports its local area reliability.	The Transmission Operator did not inform its Reliability Coordinator of two SOLs which, while not IROLs, supports its local area reliability.	The Transmission Operator did not inform its Reliability Coordinator of three SOLs which, while not IROLs, supports its local area reliability.	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs which, while not IROLs, supports its local area reliability.

TOP-002-3, R1.Each Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential single Contingency events.

TOP-002-3, M1.Each Transmission Operator shall have evidence of an assessment for next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

TOP-002-3, R1 VSL	N/A	N/A	N/A	The Transmission Operator does not have an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and potential single Contingency event conditions.

TOP-003-1, R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include:

TOP-003-1, Part 1.1, bullet #1: Long term outages of Bulk Electric System equipment, as specified by the Transmission Operator or Balancing Authority,

TOP-003-1, R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. .

TOP-003-1, R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities , the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments.

TOP-003-1, M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data that have been unfilled.

TOP-003-1, M5.Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

TOP-003-1, R4 VSL	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R2 or R3 did not satisfy the obligations of the documented specifications for data

Organization	Yes or No	Question 6 Comment
Real Time Best Practices Standards Study Group	No	The Real-time Best Practices Standards Study Group (RTBPSSG) feels that the deletion of TOP-004-2, R4 (Restore system operations from an unknown operating state to proven and reliable limits within 30 minutes) does not provide an adequate level of reliability for the operation of the Bulk Electric System (BES) and the reasoning provided for the removal is flawed. The RTBPSSG believes that this is an important consideration for operations that should not be deleted and that with more deliberations an acceptable measure for such a requirement can be developed. The concept of operating in a known state has long been a fundamental concept of reliable system operations and if this requirement is deleted then there is no requirement to cover this concept. The idea of operating to preclude IROLs or to return to within the limit in Tv does not adequately address this concern.
Response: Returning below IROLs within T_v is the same as returning from an unknown state within 30 minutes on a practical basis. T_v can be shorter than 30 minutes and thus promotes a more reliable condition. Without specific suggestions as to how to measure the deleted requirement, the SDT is unable to respond other than to maintain the current position. No action taken.		
American Transmission Company	No	We support the revised Standards. However, the questions asked do not reflect the current redlined versions of the Standards. We should be commenting on the version of the Standard that the drafting team wants to move forward with. The comment form and questions should match the current redlined version and not ask questions related to a proposed changed version.
Response: Without specific indications of where you feel errors were made, the SDT is unable to respond.		
Northeast Power Coordinating Council	No	1. We disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time."SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability?Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other 2. TOP-002-3 M1--Power flow study results will not be available for those days where studies are not required. Those days may be considered pre-studied or a normal studied state. How is this to be measured?

Organization	Yes or No	Question 6 Comment
		3. TOP-002-3 R2, R3 ? A plan should be required when the review warrants it and should include both IROL and SOL. In a normal state there may already be existing coordination between reliability entities with no need to re-communicate. 4. TOP-003-1R1: Reference to the Functional Model in the requirement may not be appropriate. This requirement may be clearer if the specific responsibilities are included. R1.1 Long Term Outages should be defined or clarified. 5. What about other outages that are potentially impactive? 6. In general, it is not clear that the data specification includes real time communications or operational planning requirements. 7. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some voice recorders are designed to retain data for 90 days. Have data recordings stored longer than 90 days only if requested by the RC or TOP.
ISO New England Inc.	No	1. We disagree with removing the requirement for the TOP to operate within SOLs. We are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time."SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state. If such upper bounds are to be ignored to enhance operating flexibility, then why should SOLs be determined in the first place and how do we ensure operating reliability? Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? 2. TOP-002-3 M1--Power flow study results will not be available for those days where studies are not required. Those days may be considered pre-studied or a normal studied state. How is this to be measured? 3. TOP-002-3 R2, R3 A plan should be required when the review warrants it and should include both IROL and SOL. In a normal state there may already be existing coordination between reliability entities with no need to re-communicate. 4. TOP-003-1R1: Reference to the Functional Model in the requirement may not be appropriate. This requirement may be clearer if the specific responsibilities are included. 5. R1.1 Long Term Outages should be defined or clarified. What about other outages that are potentially

Organization	Yes or No	Question 6 Comment
		impactive? 6. In general, it is not clear that the data specification includes real time communications or operational planning requirements. 7. The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some voice recorders are designed to retain data for 90 days. Have data recordings stored longer than 90 days only if requested by the RC or TOP.
Response: 1 – Based on the previous comments received on this issue, the industry agrees with the SDT position of deleting this phrase. You have not presented any justification or additional evidence that would cause the SDT to reverse its decision. No, the SDT does not believe the two standards contradict each other. 2 – Neither the measure nor the requirement states that you must have a power flow study for each day. The measure states that you COULD have a power flow study as one method of measuring compliance. 3 - As drafted it is required to have a plan to mitigate IROL as identified by the next day assessment. Mitigation plans are not required for "normal" states. The SDT addressed the SOL issue in point #1. 4 –The SDT agrees and has deleted the reference to the Functional Model. The timeframe indicated here is Operations Planning which incorporates one day to one year. This should be sufficient to 'define' long term. No action taken for this comment. **TOP-003-1, R1**. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include: 5 – The statement includes the term 'but not limited to' so it does not preclude the inclusion of other information. No action taken. 6 – This is a specification and not the actual transfer of data so the Time Horizon is Operations Planning. No change made. 7 – The SDT has modified Measures 4 & 5 as a result of researching your comment. The SDT has changed data retention for Requirements 4 & 5 to 90 days. **TOP-003-1, M4**. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data that have been unfilled. **TOP-003-1, M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.		
Midwest ISO Stakeholders Standards Collaborators	No	1. We believe removing the requirements for SOLs in this standard will make it unacceptable to FERC. Thus, the drafting team will have to start over when FERC remands the standard.

Organization	Yes or No	Question 6 Comment
		2. The VSLs for TOP-001-2 R2 are based on the number of times the TOP did not inform the RC of Emergency conditions. Over what time period does this apply? In perpetuity? From last compliance audit? 3. We believe the VSLs for TOP-001-2 R6 violates the Commission's guideline 4 established in their VSL order. The VSLs are based on the number times the TOP did not act to mitigate the magnitude and duration of an IROL exceedance within its Tv. However, the associated requirement states The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv. Note that the requirement talks about an IROL in the singular. Thus, failure to act on one occasion is a single violation. Failure to act on two occasions is two separate violations not a higher VSL. We suggest that a binary Severe VSL be selected or that you modify the requirement to consider IROLs in the plural. 4. In TOP-002-3, the drafting team should consider making R2 a sub-requirement of R1. Isn't it a sub-component of the assessment the TOP must have in R1? 5. R3 should be made sub-requirement of R2. 6. M1 deviates from R1 in that M1 says that the TOP shall have evidence that it performed an assessment while R1 says it shall have an assessment. Likewise, the VSL differs from the requirement in the same way and should be made to match the requirement. 7. In TOP-003-1, we note that R3 requires the BA to distribute its data specification but there is not a similar requirement to have a data specification like R1 for the TOP. 8. We believe R3 belongs in the BAL standards. 9. We also suggest that the VSLs for R4 and R5 could be graded to include multiple levels. In R4, we believe the additional VSLs could be defined based on the percentage of data that is not supplied. The VSLs for R5 could be graded based on the number TOPs and BAs that the TOP did not supply data and information to. We further believe that the portion of the requirement in R5 that applies to the BA should be moved to the BAL standards. 10. In TOP-004-3, M1 appears to be a measure of non-compliance with R1. Aren't measures supposed to identify how compliance is measured not non-compliance? The VSLs measure non-compliance.

Response: 1 – Based on the previous comments received on this issue, the industry agrees with the SDT position. You have not presented any justification or additional evidence that would cause the SDT to reverse its decision.

2 – The SDT has revised the VSL.

Organization	Yes or No	Question 6 Comment		
TOP-001-2, R2 VSL	The Transmission Operator did not inform one other Transmission Operator of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform two other Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform three other Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or anticipated Emergency conditions. OR The Transmission Operator did not inform four or more other Transmission Operators of an actual Emergency or anticipated Emergency conditions.
3 – The SDT agrees with the suggested change to the VSL.				
TOP-001-2, R6 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL which, while not an IROL, support its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs which, while not IROLs, support its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs which, while not IROLs, support its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs which, while not IROLs, support its local area reliability**.**
4 & 5 – The SDT believes these are separate standalone requirements. No change made. 6 – The SDT has changed M1 and the R1 VSL. **TOP-002-3, M1**. Each Transmission Operator shall have evidence of an assessment for next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.				
TOP-002-3, R1 VSL	N/A	N/A	N/A	The Transmission Operator does not have an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and potential single Contingency

Organization	Yes or No	Question 6 Comment		
				event conditions.

7 – Please see R2 of TOP-003-1.

8 – The SDT does not believe that there is a relevant spot in the BAL standards for such a requirement. No change made.

9 – The SDT has reworded Requirement R4, M4, and the wording of the Severe VSL to accommodate your concerns. The SDT does not feel that with this new wording any change is required to add levels of VSL. The SDT reviewed the R5 VSL and feels that it is correct and has not made a change in this area.

> **TOP-003-1, R4**. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. .
>
> **TOP-003-1, M4**. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data that have been unfilled.

TOP-003-1, R4 VSL	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R2 or R3 did not satisfy the obligations of the documented specifications for data. .

10 – The SDT felt it would be easier to provide information if and when an IROL and IROL T_V was violated compared to providing information of every operating hour proving that an IROL and IROL T_V was not violated. No change made.

Organization	Yes or No	Question 6 Comment
FirstEnergy Corp	No	1. The drafting team's response to FE's fifth comment in the Draft 1 Question 12 is not sufficient for us to understand their thought process on the matter. Our prior comment raised a concern with the removal of TOP-007-0 R3 that states, "A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load ?? The SDT responded that this matter is covered in EOP-001-0, Requirement R3.3 that states, R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.? 2. The SDT is proposing to retire PER-001 and FE believes the PER-001 requirement R1 and its associated measure M1.4 should be re-enforced within the TOP standards. This operator authority was a focal point of recent readiness evaluations within the industry and should be explicit within a TOP

Organization	Yes or No	Question 6 Comment
		requirement. We would appreciate further explanation from the SDT if they feel the change is still not required. 3. FE disagrees with the SDT's response to our comment on Draft 1 Q4 which questioned which contingencies are required to be evaluated within the operating horizon. The prior TOP-002-2 requirement R6 stated R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements. This concept is lost in the newly proposed TOP standards. In responding the SDT stated that the Transmission Operator is not limited to single Contingencies or bus faults but must study any and all conditions that may result in exceeding any of its System Operating Limits during anticipated normal conditions as stated in the Requirement. The potential Contingencies to be studied are limited to those spelled out in the TPL standard. FirstEnergy does not agree that there is an expectation to cover all TPL contingencies within the operating horizon. As vetted by industry in the recent proposed and subsequently withdrawn SAR that proposed to evaluate credible multiple contingencies? it is clear that studies within the planning and operations horizon are distinctly different and that there is no expectation to cover events in real-time or within the operating horizon (next day, next month, through one year out) beyond single contingency. We ask the SDT to clarify their comment in this regard. 4. We would like the SDT to explain why it found the need to introduce the term each in requirement R1 of TOP-002-1. As re-worded, the focus of the compliance audit may become too structured on strict adherence to each directive rather than the TOP meeting the intent of the RC's directives. If the wording remains, we believe the VSLs can be better graded and that missing a single directive should not warrant a severe VSL. Many of the proposed VSLs use a quartile approach (0-25%, 25-50%,50%-75% and >75%) of gauging if some reliability action was missed. FERC in its VSL Order dated June 19, 2008 took exception to the quartile approach and felt it violates its Guideline 1 ?Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance? see paragraphs 19 through 21. The VSL DT revised the VLS that previously used a quartile score to reflect a 0-5%, 5%-10%, 10-15% and >15% graded VSL approach. Its suggested that the SDT reconsider its use of quartile VSLs. 5. We believe the VSLs for TOP-001-2 R6 violates the Commission's Guideline 4 established in their VSL order. The VSLs are based on the number times the TOP did not act to mitigate the magnitude and duration of an IROL exceedance within its Tv. However, the associated requirement states The Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's Tv. Note that the requirement talks about an IROL in the singular. Thus, failure to act on one occasion is a single violation. Failure to act on two occasions is two separate violations not a higher VSL. We suggest that a binary Severe VSL be selected or that you modify the

Organization	Yes or No	Question 6 Comment
		requirement to consider IROLs in the plural. 6. In TOP-003-1 R1.1 second bullet the SDT introduced a new requirement that for data exchange related to equipment at voltage levels below the BES and left the need for this data at the discretion of the TOP or BA. FirstEnergy believes the inclusion of equipment lower than normal BES levels should not be introduced on an ad-hoc standard by standard basis. Rather, if such equipment is deemed necessary for the reliability of the BES then the Facilities may need to be subject to other reliability standards such as vegetation management, preventative maintenance, etc. Inclusion of such equipment should be a registration issue handled through the Regional Entity and not within individual standard requirements. However, providing such data could be requested and provided on a voluntary basis, but if the equipment is deemed essential for BES reliability other standards likely apply.

Response: 1 – The SDT apologizes for any confusion. The duplicative standard is EOP-001-0, Requirement R2.3.

2 – The SDT deleted this requirement for numerous reasons. First, it is not measurable. Second, the standards themselves, once approved by FERC, not only grant but demand operating personnel implement real-time actions to ensure stable and reliable operations of the BES. No change made.

3 – The SDT has reviewed its response provided to the comments from First Energy for Q4 in Draft 1 and agrees that it was incorrect. The SDT added the word 'single' to TOP-002-3, Requirement R1 to clarify its position which is based on the development of the new TPL-001-1 standard.

> **TOP-002-3, R1**. The Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential single Contingency events.

4 – The SDT believes that you meant TOP-001-2, Requirement R1. The SDT believes that if an entity misses a reliability directive, it is a Severe violation. No change made.

5 – The SDT agrees with the suggested change to the VSL.

TOP-001-2, R6 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL which, while not an IROL, supports its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs which, while not IROLs, supports its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs which, while not IROLs, supports its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs which, while not IROLs, supports its local area reliability**.**

6 – The SDT did not introduce a new requirement but was responding to a directive in Order 693, paragraph 1626 when this bullet was crafted. The SDT believes that if this data is required for planned outages then it is also important enough to be required in general. No change made.

Organization	Yes or No	Question 6 Comment
IRC Standards Review	No	(1) We believe there is a fundamental principle that TOPs need to operate their systems within SOLs. We propose the SDT re-instate the deleted words from TOP-004 R1 that address SOLs. Recognizing that not

Organization	Yes or No	Question 6 Comment
Committee		all SOLs have an impact on interconnected system reliability if their exceedances are not mitigated within some target time period, we propose the SDT consider qualifying the SOLs which the TOP must operate within along the same line as we propose in our comments under Q2, namely, the set to be identified by the TOP subject to its RC's concurrence.(Please note that ERCOT abstained from these comments) To more fully address the issue with some SOLs that do not have any reliability impacts, we propose the SDT consider revising the definition of SOL. This will eliminate the need for each TOP to identify this subset and obtain the RC's concurrence. (2) We generally support the direction the SDT is moving but would require consideration of the comments provided in this transmittal.What is replacing TOP-001 R7? The requirement was previously TOP-008-R2, got moved to TOP-001 R7, but now both TOP-001 R7 is deleted and TOP-008 is deleted. Is there still going to be a requirement to use the most restrictive limit when multiple entities have different limits? (3) TOP-003-1 makes reference to functional responsibilities and responsibilities per the NERC Functional Model. We do not agree with these references since it is unclear the status of the NERC Functional Model and how it relates to the NERC Standards. It has been noted that the NERC Functional Model is only for guidance and is not a standard.
Response: 1 – Based on the previous comments received on this issue, the industry agrees with the SDT position of deleting this. You have not presented any justification or additional evidence that would cause the SDT to reverse its decision. For clarity, the SDT has added a new requirement to TOP-001-2 to cover the issue on SOLs that must be reported. **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. 2 – As pointed out in the responses to comments for the first posting, the SDT deleted this requirement as it is duplicative of IRO-05-3, Requirement R10. 3 – The SDT agrees and has changed the requirement accordingly. **TOP-003-1, R1**. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include:		
Exelon	No	In general, Exelon supports the revisions and appreciates the work being done by the SDT to consolidate and clarify the requirements. We have some concerns with the langauge in TOP-001-2 R4."Coordinate" - We believe this needs to be better defined. "Known or expected to have a reliability impact" – Reliability impact needs to be defined better, can measures be identified, such as; cause a system to violate a limit under expected conditions? Consider adding the words in the judgment of the TOP before the word expected. Otherwise this may become a point of contenetion and difficulty during an audit.If the GO is not removed (see question 2)the GO is not

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>likely to have the ability to know what reliability impacts its actions might have."other reliability entities" - needs to be defined.

"Unless conditions do not permit such coordination" - if this clause is getting at the issue of time not available, consider unless based on the reasonable judgment of the TO, considering the facts and circumstances at the time, conditions do not permit such coordination.? We feel the point of the requiremnts should be when a GO/TO knows or reasonably should know that an action will have a substantial adverse reliability impact on another operating entity (define), the GO/TO should inform the other entity and consider that other entity's input in deciding how to operate, if time permits.</td></tr>
<tr><td colspan="3">Response: The SDT believes that through analysis, reliability impacts on other reliability entities will be known and/or expected and this information should be shared to support reliability. No change made.

The SDT does not see an industry consensus for removing the Generator Operator from this requirement. However, the Generation Operator will not know what causes an impact unless they have been told so by the Transmission Operator. Therefore, the SDT has added the suggested wording to the requirement.

TOP-001-2, R4. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected by the Transmission Operator to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. Such operations include, but are not limited to, relay or equipment failures and changes in generation, Transmission, Load, or operating conditions.

The SDT believes the requirement as drafted is sufficient. No change made.</td></tr>
<tr><td>Consumers Energy Company</td><td>No</td><td>TOP-003-1 R1.1 needs to be more specific in identifying the equipment to be considered for inclusion.</td></tr>
<tr><td colspan="3">Response: The SDT believes the individual entities are best capable of determining the data required to fulfill their reliability functions. No change made.</td></tr>
<tr><td>Duke Energy</td><td>No</td><td>- TOP-001 R2 Need to change affected to adjacent, and in the VSLs.- TOP-001 R4 Change other to adjacent,

- and in the VSLs.- TOP-001 R4 If coordinating means that we're posting the information on SDX, then we are in agreement.-

- TOP-001 R6 Need clari</td></tr>
<tr><td colspan="3">Response: Based on stakeholder comments, the SDT changed, "affected" to "other" in TOP-001, Requirement R2. 'Other' provides flexibility and includes "adjacent."

The SDT believes that posting on SDX could be coordination but that the key element is that actions are coordinated in some manner. No change made.</td></tr>
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<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td>New York Independent System Operator</td><td>No</td><td>We generally support the direction the SDT is moving but would require consideration of the comments provided in this transmittal.What is replacing TOP-001 R7? The requirement was previously TOP-008-R2, got moved to TOP-001 R7, but now both TOP-001 R7 is deleted and TOP-008 is deleted. Is there still going to be a requirement to use the most restrictive limit when multiple entities have different limits?

TOP-003-1 makes reference to functional responsibilities and responsibilities per the NERC Functional Model. We do not agree with these references since it is unclear the status of the NERC Functional Model and how it relates to the NERC Standards. It has been noted that the NERC Functional Model is only for guidance and is not a standard.

The Data Retention change in Section D 1.4 of TOP-003-1, Operational Reliability Data, from 90 calendar days to three calendar years is excessive. Voice recorder designs vary, and some are designed to retain data for 90 days. The SDT should take into consideration the storage media. In some cases equipment is changed and the data may not be obtainable, or cost prohibited.</td></tr>
<tr><td colspan="3">Response: As pointed out in the responses to comments for the first posting, the SDT deleted this requirement as it is duplicative of IRO-05-3, Requirement R10.

The SDT agrees and has changed the requirement accordingly.

TOP-003-1, R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include:

The SDT has modified Measures 4 & 5 as a result of researching your comment. The SDT has changed the data retention for Requirements 4 & 5 to 90 days.

TOP-003-1, M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data that have been unfilled.

TOP-003-1, M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.</td></tr>
<tr><td>CenterPoint Energy</td><td>No</td><td>CenterPoint Energy believes reliability requirements should not include vague and unmeasurable, fill-in-the-blank provisions, like those shown in TOP-003 Requirement 1. R1 states Each Transmission Operator and Balancing Authority shall have a documented specification for data required to fulfill their respective responsibilities per the NERC Functional Model. In addition, CenterPoint Energy disagrees with the accompaning TOP-003 Requirement 4 that requires numerous entities to comply with fill-in-the-blank provisions developed through R1. As written, R1 leaves it open to the whim of a Transmission Operator or Balancing Authority to conjure a list of required data, without any process for impacted entities</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
		to argue the reasonabless of the data. In R1.1, the SDT has added two examples of required data by stating Long term outages of Bulk Electric System equipment when they are known and Equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority?. These vague examples leave it to the total discretion of a Transmission Operator or Balancing Authority. CenterPoint Energy recommends rewording Requirement 1 and deleting TOP-003 Requirement 4.
Response: The SDT has changed Requirements R1 and R4 to provide clarity to this issue. **TOP-003-1, R1**. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include: **TOP-003-1, R4**. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data.		
Independent Electricity System Operator	No	We do not support the revised standards. Our biggest concern is the removal of the requirement for TOP to operate within SOLs as stated in our response to Q#3. As stated in our previous comments we are unable to understand the argument that this requirement will "reduce the operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time."SOLs are determined to set upper bounds beyond which transmission facilities may be overloaded or system voltage may be depressed or the operators will be operating in an unknown state, even before IROL violations become evident. If such upper bounds are to be ignored to enhance operating flexibility, the BES would be very vulnerable to instability, uncontrolled separation, or cascading outages upon the occurrence of subsequent contingencies. The 2003 blackout started off with an SOL violation, and is a good example of how a "localized" problem can propagate thru the interconnected network to become a widespread reliability problem.Further, FAC-014 requires TOPS to develop SOLs, why would we be requiring the TOPs to do so while we suggest that they do not need to operate within the bounds that they themselves develop in the first place? Do the two sets of standards contradict each other? We are also very concerned that R1/R2 in TOP-002 requires the TOP to assess potential exceedence of IROLs only but not SOLs. We feel strongly that R2 in TOP-002 should be revised so that it includes as part of the requirement, preclusion of operating in excess of any SOLs. Further, we believe that all SOLs should be respected in the planning time-frame and in real time with the exception of low likelihood or rare circumstances. WE believe the SDT may have misinterpreted our previous comments. By system voltage may be depressed? we were saying the voltage may be lower than normal, we did not explicit state or imply that the depressed voltage will cause a collapse which appeared was the basis of the SDT's response that we

Organization	Yes or No	Question 6 Comment
		were talking about IROL - a subset of SOL. The argument that the TOP is required to calculate SOL but does not need to operate within all the time seems irrational. Operating with SOL all the time and correct exceedance within some defined time period is necessary to ensure reliability. The examples/rationale cited in the question asked in the previous comment form: The SDT felt that requiring a TOP to operate within all SOLs could effectively reduce the TOPs operational flexibility by eliminating the TOP's ability to determine that a mitigation, such as load shedding, was more severe than the risk of the SOL violation itself, such as exceeding a thermal limit for a short time. was but one such situation. Load shedding to reduce equipment loading is often regarded by TOPs as an exception, i.e., load is not shed to correct a temporary exceedance of equipment rating or a potential exceedance of applicable equipment rating if a contingency were to occur. The rationale is simply to not shed load if exceedance of the facility's continuous rating is expected to be temporary, or if a contingency were to occur then the expected loading will exceed the concerned equipment's applicable rating since we do not shed load pre-contingency to avoid shedding load after a contingency has occurred.Operating within an SOL w/o having to shed load under some circumstances is clearly conveyed in our comments (underlined in our comments above). However, without the fundamental requirement to operating within SOL, it opens the door to various kinds of unreliable operating conditions. A first overloaded line, which trips because it loading is not corrected, will cause loading on other lines to increase. There is no certainty as to when and where loading on the remaining system will cease to cause additional tripping. Also, the absence of such a requirement begs the question on the need to:(a) Calculate SOL (FAC-014) in the first place. The SDT's response that FAC-014 also requires the TOP to ?communicate your SOLs to other entities so that they can respect your operational limits? seems a bit unfair since the TOP, as the SOL developer, does not itself need to respect the SOL but others do. And who are these ?other entities? within the TOP area that need to respect the SOLs - The BA, GOP or the RC, while the TOP has the transmission reliability authority within its area and takes primary responsibility in transmission reliability (other than the RC who has a wide-area view and has the final authority)? (b) Perform day ahead analysis (TOP-002, R1) without requiring any follow-on actions if the analysis shows that SOLs will be exceeded. Developing SOLs and assessing if they will be exceeded would simply be an academic exercise. We are unable to determine how will not respecting SOLs and not having follow-on actions when SOLs are assessed to be exceeded contribute to reliability? (c) Report exceedances and corrective actions taken (TOP-001, R5). This serves no purpose if a TOP is not required to operate within SOLs. (2) TOP-002, R1 requires a TOP to assess next day operations and identify if any SOLs will be exceeded, and the actions related to SOL stops there. It is irresponsible for the TOP to not do anything such as adjusting outage plans and/or requesting adjustment to resource plans to arrive at operating conditions that will no cause SOLs to be exceeded. A requirement similar to that of R2 (for the IROL) should be developed. The only difference between them would be the need to prepare for load shedding when

Organization	Yes or No	Question 6 Comment
		mitigating measures run out. (3) We noted that some VSLs are graded according to the number of occurrences. Please refer to the recent posting on the revised VSLs for 8 sets of standards, in which the VSLSDT made reference to the June 2008 FERC Order on VSL. In the Order, FERC provided a guideline (among others) that VSLs should not be determined by the number of occurrence. Specifically, FERC's Guideline #4 stipulates that:Guideline 4 VSLs should be based on a single violation, not on a cumulative number of violations (unless stated otherwise in the requirement).We suggest the SDT to revise these VSLs accordingly.
Response: Based on the previous comments received on this issue, the industry agrees with the SDT position of deleting this requirement. You have not presented any justification or additional evidence that would cause the SDT to reverse its decision. The SDT has added TOP-001-2, Requirement R6 and modified TOP-001-2, Requirement R7 to provide clarity around this position. The SDT does not feel that the 2 standards contradict each other. **TOP-001-2, R6.** Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs) which, while not IROLs, support its local area reliability**.** **TOP-001-2, R7**. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOLs as identified in Requirement R6, has been exceeded. TOP-002-3 is for planning purposes only. TOP-001-2 addresses operations. TOP-002-3, Requirement R1 explicitly requires the assessment of SOLs and Requirement R2 states that you should *plan* to avoid operating in excess of IROLs. You have not presented any evidence to convince the SDT to change our position and the majority of the industry agrees with the SDT's position. A change was made to TOP-001-2 to address operations as shown above. The SDT feels that TOP-002-3, Requirements R1 & R2 provides sufficient assurance that the next day operations will be reliable. The SDT does not agree with the contention that the revised standards will lead to unreliable operating conditions nor have you provided evidence of this contention. The SDT has not received consequential comments to cause the SDT to change its position. No change made. (b) The SDT feels that TOP-002-3, Requirements R1 & R2 provides sufficient assurance that the next day operations will be reliable. The SDT does not agree with the contention that the revised standards will lead to unreliable operating conditions nor have you provided evidence of this contention. The SDT has not received consequential comments to cause the SDT to change its position. No change made. (c) The SDT has modified TOP-001-2, Requirement R7 to provide clarity on what SOLs need to be reported. (2) The SDT feels that TOP-002-3, Requirements R1 & R2 provides sufficient assurance that the next day operations will be reliable. The SDT does not agree with the contention that the revised standards will lead to unreliable operating conditions nor have you provided evidence of this contention. The SDT has not received consequential comments to cause the SDT to change its position. No change made. (3) If the requirement is singular, then each occurrence is a separate violation. If the requirement is plural, then multiple occurrences are a single violation. The SDT believes this is consistent with the FERC Order on VSLs. Without specific references, the SDT sees no reason for change.		
Southern Compnay	No	TOP-001 R2: The phrase shall coordinate its respective operations known or expected to have a reliability

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>impact on other reliability entities could cause compliance issues due to the resulting subjectivity of the identification of other reliability entities. Recommend that it replaced with shall coordinate its respective operations known or expected to have a reliability impact on adjacent reliability entities?. It should be the responsibility of the adjacent reliability entity to further coordinate, if necessary, other appropriate reliability entities. The Measures and VSLs would need to be modified accordingly

.TOP-002 R2 uses the word "plan" as a verb, and then it is referenced in R3 as a noun. This is propagated in the Measures and VSLs. Suggest the following wording change in R2: The Transmission Operator shall have a coordinated plan??

TOP-003 R1.1 - suggest that "Long term" be removed and replaced with "Planned". "Long term" could be interpreted to mean an outage that will not occur for quite some time (long lead time), or an outage that will occur sooner but will last for a long time. All outages should be communicated.

R1.2 - Disagree with this requirement. We recommend that it be struck. The TO and the BA must be able to specify formats that can be utilized by their processes to ensure reliability.</td></tr>
<tr><td colspan="3">Response: The word ‘coordinate’ is not used in TOP-001-2, Requirement R2 but upon review the SDT has modified the wording to address your concern about affected Transmission Operators.

TOP-001-2, R2. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions.

The SDT sees no reason to change the wording in TOP-002-3, Requirements R2 & R3. Plan can be both a noun and a verb and the usage here is self-explanatory.

Long term is ‘defined’ by the use of the Operations Planning Time Horizon which is limited to one year.

The SDT believes that R1.2 is a reasonable attempt to solve the problem where there are 2 different systems involved. Deleting the requirement doesn’t solve the problem. No change made.</td></tr>
<tr><td>Brazos Electric Power Cooperative, Inc.</td><td>No</td><td>See responses to previous questions.</td></tr>
<tr><td colspan="3">Response: Please see responses to previous comments.</td></tr>
<tr><td>Bonneville Power Administration</td><td>Yes</td><td>Some suggestions:TOP-002-3 1) R1. Remove "and potential Contingency events". Any event could temporarily increase flows over the SOL (or IROL) or cause the SOL to decrease until the flows are mitigated per ROP-001. The system studies set the SOL's to protect the system for such events. The mitigation is then required in TOP-001-2 then (and TOP-004 if it is kept).</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
		2) R1. Reword R1 similar to that of R2 in that TOP "plans" to preclude operating in excess of any SOLs for anticipated normal conditions. This is normal operational planning. All entities should not be planning to exceed SOL for normal conditions. Rewording: R1. "The Transmission Operator shall plan next days operation to preclude operating in excess of any System Operating Limits (SOLs) during anticipated normal conditions."
Response: The SDT believes that the phrase must remain as you must perform an assessment including Contingencies to properly analyze any exceedances of SOLs. The SDT feels that TOP-002-3, Requirements R1 & R2 provide sufficient assurance that the next day operations will be reliable. The SDT does not agree with the contention that the revised standards will lead to unreliable operating conditions nor have you provided evidence of this contention. The SDT has not received consequential comments to cause the SDT to change its position. No change made.		
Project 2007-02 Operating Personnel Comm Protocols SDT	Yes	The Operating Personnel Communication Protocols standard drafting team respectfully requests that the Real Time Operations team incorporate the following into your proposed TOP-001: ?Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have procedures for the communication of information concerning the transmission emergency alerts in accordance with the conditions described in Attachment 1 Transmission Emergency Alerts .? In addition, the Applicability Section 4 would need to include Reliability Coordinators. The Operating Personnel Communications Protocols Project 2007-02 was initiated to ensure that real time system operators use standardized communication protocols during normal and emergency operations to improve situational awareness and shorten response time. The SDT developed a new COM-003-1 Standard that has yet to be posted and is dependent upon revising at least two other standards (CIP-001 and appropriate TOP Standard). COM-003 contains requirements that specify:1. Use of three-part communication; 2. English language; 3. Common time zone; 4. NATO alpha-numeric alphabet; 5. Mutually agreed line identifiers; 6. The use of pre-defined system condition terminology such as those contained in the RCWG Alert Level Guide and EOP-002-2.This request is based on recent NERC Standards Committee direction to our team to incorporate the Reliability Coordinator Working Group’s (RCWG) Alert Level Guide into a Standard. The consensus of our team is that a TOP Standard is the most appropriate location for the Transmission Emergency Alert language from the Guide as the energy emergency alert language is currently described in EOP-002-2. The RCWG Guide proposes the use of pre-defined system condition descriptions for use during emergencies for reliability related information. This guide was developed in response to a Blackout Report recommendation. Our team placed the energy cyber and physical security emergency alert language into CIP-001. Since the Real Time Operations SDT is currently modifying TOP-001 through 004, we seek your consent to incorporate the transmission emergency alert language to comply with the wishes of the Standards Committee.We believe that a TOP

Organization	Yes or No	Question 6 Comment
		Standard is the most appropriate location for this language for the following reasons:? The levels of emergency conditions related to the transmission system is based upon maintaining the transmission system within Interconnection Reliability Operating Limits. ? Your proposed TOP-001 R2 already requires the sharing of information of actual and anticipated transmission emergency conditions and the use of pre-defined terminology supports the efficient sharing of such information. The following text is appended here for the record. It is the OPCP SDT proposal for a revised TOP Standard that incorporates the TEA material.Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 1 of 17Effective Date: October 1, 2007A.Introduction1.Title: Transmission Operations2.Number: TOP-004-33.Purpose: To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies; and to communicate transmission emergency alerts.4.Applicability:4.1.Reliability Coordinator4.2.Balancing Authority4.3.Transmission Operators5.Proposed Effective Date: First day of first calendar quarter, one calendar year following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter a year from the date of Board of Trustee adoption.B.RequirementsR1.Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).R2.Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.R3.Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.R4.If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.R5.Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.R6.Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:R6.1.Monitoring and controlling voltage levels and real and reactive power flows.R6.2.Switching transmission elements.R6.3.Planned outages of transmission elements.R6.4.Responding to IROL and SOL violations.R7.Each Reliability Coordinator, Balancing Authority, and Transmission Operator shall have procedures for the communication of information concerning the transmission emergency alerts in accordance with the conditions described in Attachment 1-TOP-004-3.C.MeasuresStandard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 2 of 17Effective Date: October 1, 2007M1.Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide

Organization	Yes or No	Question 6 Comment
		upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.M2.Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.M3.Each Reliability Coordinator, Balancing Authority, Transmission Operator shall have and provide upon request the procedures or guidelines that will be used to confirm that it meets Requirement 7.Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 3 of 17Effective Date: October 1, 2007D.Compliance1.Compliance Monitoring Process1.1.Compliance Monitoring ResponsibilityRegional Reliability Organizations shall be responsible for compliance monitoring.1.2.Compliance Monitoring and Reset Time FrameOne or more of the following methods will be used to assess compliance:-Self-certification (Conducted annually with submission according to schedule.)-Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)-Periodic Audit (Conducted once every three years according to schedule.)-Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)The Performance-Reset Period shall be 12 months from the last finding of non-compliance.1.3.Data RetentionEach Transmission Operator shall keep 90 days of historical data for Measure 1.Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data1.4.Additional Compliance InformationNone.2.Levels of Non-Compliance:2.1.Level 1: Not applicable.2.2.Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.2.3..Level 3: Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.Standard TOP-004-3 Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 4 of 17Effective Date: October 1, 20072.4.Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:2.4.1Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.2.4.2Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.E.Regional DifferencesNone identified.Version HistoryVersionDateActionChange Tracking0April 1, 2005Effective DateNew0August 8, 2005Removed Proposed from Effective DateErrata1November 1, 2006Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November

Organization	Yes or No	Question 6 Comment
		1, 2006Revised2December 19, 2007Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)RevisedErrataStandard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 5 of 17Effective Date: October 1, 2007Attachment 1-TOP-004-3 Transmission Emergency Alert (TEA) LevelsIntroductionThis Attachment provides the procedures by which a Transmission Operator or Reliability Coordinator can advise of actions taken to manage potential or actual Interconnected Reliability Operating Limit (IROL) violations.All three operating alert states (EEAs, TEAs and SEAs) are independent of each other and should be declared independently but they may also be declared concurrently.A. General Requirements1. Initiation by Reliability Coordinator. A Transmission Emergency Alert (TEA) may be initiated only by a Reliability Coordinator at:1) the Reliability Coordinator's own request, or2) upon the request of a Transmission Operator1.1. Situations for initiating alert. A Transmission Emergency Alert may be initiated for the following reasons: When all the available generation resources (would also include dispatchable load facilities that dispatch similar to generators on an economic basis) have been committed to respect an IROL in the pre-contingency state or; When load curtailment procedures have been implemented to respect an IROL.2. Notification. A Reliability Coordinator who declares a Transmission Emergency Alert shall notify all Transmission Operators and Balancing Authorities in its Reliability Area. The Reliability Coordinator shall also notify Reliability Coordinators of the situation via theReliability Coordinator Information System (RCIS) using the System Emergency category. Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify all Transmission Operators and Balancing Authorities in its Reliability Area and Reliability Coordinators when the alert has ended.B. Transmission Emergency Alert LevelsIntroductionStandard TOP-004-3 Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 6 of 17Effective Date: October 1, 2007To ensure that all Reliability Coordinators clearly understand potential and actual actions taken to manage IROLs on the Interconnection, NERC has established three levels of Transmission Alerts. The Reliability Coordinators will use these terms when explaining actions taken to manage IROLs to each other. A Transmission Emergency Alert is an emergency communication protocol , not a daily operating practice, and is not an alternative to compliance with NERC reliability standards. The Reliability Coordinator may declare whatever alert level is appropriate, and need not proceed through the alerts sequentially.1. Transmission Emergency Alert 1 (TEA 1) ? All available generation resources committed to respecting IROLs.Circumstances: The Reliability Coordinator or Transmission Operator foresees or is experiencing conditions where all available generation resources are committed to respect the IROL and/or is concerned about its ability to respect the IROL.2. Transmission Emergency Alert 2 (TEA 2) Load management procedures in effect to respect IROLs.Circumstances: The Reliability Coordinator or Transmission Operator foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:?Public

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		appeals to reduce demand.?Voltage reduction. Interruption of non-firm end use loads in accordance with applicable contracts (for emergency purposes, not economic reasons) Demand-side management.Utility load conservation measures?TLR 6Note: TLR 5 would normally be implemented in advance of this alert state. Under some circumstances TLRs may not be available or effective and would not be called prior to this alert state.During TEA 2, Reliability Coordinators and Transmission Operators have the following responsibilities:2.1 Declaration period. The declaring Reliability Coordinator shall update the RCIS under System Emergency at a minimum of every hour until the TEA 2 is terminated.2.2 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may be contributing to the alert level. Where appropriate, the Reliability Coordinators shall inform the Transmission OperatorsStandard TOP-004-3 Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 7 of 17Effective Date: October 1, 2007under their purview of the pending Transmission Emergency Alert and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures and redispatching generation.The following additional actions should also be considered where appropriate: Notification of ATC adjustments. Resulting increases in ATCs shall be communicated to the market via posting on the appropriate OASIS websites by the Transmission Providers. Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the declaring Reliability Coordinator. Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the declaring entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators. Initiating inquiries on re-evaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of re-evaluating and revising SOLs or IROLs.2.3 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.2.4 Actions Prior to Declaration of TEA 3. Before declaring a TEA 3, all available generation resources must be committed. This includes but is not limited to: All available generation units are on-line. All generation capable of being on-line in the time frame of the emergency is on-line including quick-start and peaking units, regardless of cost. Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost. Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 8 of 17Effective Date: October 1, 2007?Operating Reserves. Operating reserves are being utilized such that the declaring entity may be carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.3.

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		Transmission Emergency Alert 3 (TEA 3) ? Firm load curtailment in effect to respect IROLs.Circumstances:The Reliability Coordinator or Transmission Operator foresees or has implemented firm load obligation interruption to respect an IROL.3.1 Continue actions from TEA 2. The Reliability Coordinators and the declaring entity shall continue to take all actions initiated during TEA 2.3.2 Declaration Period. The declaring Reliability Coordinator shall update the RCIS under ?System Emergency? at a minimum of every hour until the TEA 3 is terminated.3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities.3.4 Re-evaluating and revising SOLs and IROLs. The Reliability Coordinator of the declaring entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Re-evaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the declaring entity who has requested an TEA 3 condition. SOLs and IROLs shall only be revised as long as a TEA 3 condition exists or as allowed by the Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.3.5 Returning to pre-emergency SOLs and IROLs. Whenever the transmission systems can be returned to their pre-emergency SOLs or IROLs, the declaring Entity shall notify its respective Reliability Coordinator.3.5.1 Notification of other parties. When an alert has been downgraded, the Reliability Coordinator shall notify via the RCIS the affected Reliability Coordinators, Transmission Operators and Balancing Authorities that their systems can be returned to their normal limits.Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 9 of 17Effective Date: October 1, 20074. Transmission Emergency Alert 0 (TEA 0) - Termination.When the declaring Entity is able to respect IROL requirements and is no longer concerned with its ability to respect IROLs, it shall request its Reliability Coordinator to terminate the alert.4.1. Notification. The Reliability Coordinator shall notify Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Transmission Operators and Balancing Authorities.RCIS Posting ExamplesEach RCIS posting should be clear and concise. If the actions are being taken as a result of a contingency, the contingency should also be identified as the cause.The following are examples of possible of RCIS postings:TEA 1(name of RC) is declaring a TEA 1 on the (name of the interface).TEA 2(name of RC) is declaring a TEA 2 on the (name of the interface). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of (type of load management procedures that have been or expected to be implemented ie voltage reduction, curtailable load reductions) of relief has been (or is expected) to be implemented to respect the limit. These actions are expected to last the next (length of time ? hours/days) and should be sufficient to prevent the need for Firm load shedding.TEA 3(name of RC) is declaring a TEA 3 on the (name of the

Organization	Yes or No	Question 6 Comment
		interface). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of Firm Load curtailments have been (or is expected) implemented to respect the limit. These actions are expected to last the next (length of time ? hours/days).Contingency ExampleIf the TEA is being declared as a result of a contingency the message could be modified simply by adding the contingency description as below:(name of RC) is declaring a TEA 2 on the (name of the interface). This is a result of a contingency on (name of the interface or contingent element). Flows from (direction of flow that impacts the interface) aggravate this interface. (amount of MW relief) of (type of load management procedures that have beenStandard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 10 of 17Effective Date: October 1, 2007or are expected to be implemented i.e. voltage reduction, curtailable load reductions) to respect the limit. These actions are expected to last the next (length of time ? hours/days) and should be sufficient to prevent the need for Firm load shedding.UpdatesWhen updating postings only significant changes need be identified. The following is appropriate:(name of RC) remains in a TEA (2 or 3) on the (name of the interface). (amount of MW relief) of (type of load management procedures that have been or are expected to be implemented i.e. voltage reduction, curtailable load reductions, firm load reductions) have been implemented (description of the change i.e. increased/reduce by amount of MW change or identify no change).Standard TOP-004-3 ? Transmission OperationsExample #1IROL violation on X No Global Adequacy ConcernsIROL ?X?500 MW - A to B300 MW - B to AIntertie Limit Intertie LimitImp 300 Imp 200Exp 200 Exp 100EEA1 No2 No3 NoTEA1 Yes2 Yes3 YesIn this example the available generation in A is in excess of its load requirements. The available generation in B is less than its load requirements. Area B will be relying on the full transfer capability of the interface ?X? plus an additional import of 100 MW to the maximum limit on the intertie in Area B. With the implementation of the interruptible load and V/R the firm load requirements in B cannot be met without the use of Firm load shedding.In this scenario an EEA is not required as the BA is able to meet its globalBA Total Load 2,500 MWBA Total Gen 2,900 MWBAImpLimit500MWZone AZone BLoad 1,500 MWLoad 1,000 MWGen available 2,800 MWGen available 100 MWImp 0 MWImp 100 MWExp 0 MWExp 0 MWInterruptible 50 MWLoadInterruptible 50 MWLoadV/R 50 MWV/R 50 MWBalancing Authority X Adopted by Board of Trustees: November 1, 2006 Page 11 of 17Effective Date: October 1, 2007Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 12 of 17Effective Date: October 1, 2007load/generation requirements .When this situation is forecast a TEA 1 should be issued to indicate the potential concerns with the ability to respect the IROL limit X without the use of load management procedures. When load management procedures are implemented in Real Time to respect the IROL X, a TEA 2 should be issued.When Firm load is curtailed to respect the limit a TEA 3 should be issued.Standard TOP-004-3 ? Transmission OperationsExample #2Global Adequacy DeficiencyNo IROL ViolationIROL ?X?500 MW - A to B300 MW - B to AIntertie Limit Intertie LimitImp 300 Imp 200Exp 200 Exp 100EEA1 Yes2 Yes3 NoTEA1 No2 No3 NoIn this example the available generation in A is less than its load requirements. The available generation in B is less than its load requirements. There is a Global Adequacy deficiency after considering full import capability and

Organization	Yes or No	Question 6 Comment
		utilization of interruptible load and V/R.BA Total Load 2,500 MWBA Total Gen 1,800 MWZone AZone BLoad 1,500 MWLoad 1,000 MWGen available 900 MWGen available 900 MWImp 300 MWImp 200 MWExp 0 MWExp 0 MWInterruptible 100 MWLoadInterruptible 50 MWLoadV/R 50 MWV/R 50 MWBalancing Authority X Adopted by Board of Trustees: November 1, 2006 Page 13 of 17Effective Date: October 1, 2007Standard TOP-004-3 Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 14 of 17Effective Date: October 1, 2007?EEA procedures should be followed?There is no need for a TEA to be issuedStandard TOP-004-3 ? Transmission OperationsExample #3Global Adequacy DeficiencyIROL ViolationIROL ?X?500 MW - A to B300 MW - B to AIntertie Limit Intertie LimitImp 300 Imp 200Exp 200 Exp 100EEA1 Yes2 Yes3 NoTEA1 Yes2 Yes3 YesIn this example the available generation in A meets its load requirements. The available generation in B is less than its load requirements. There is a Global Adequacy deficiency after considering full import capability. There is also an IROL violation at X in the direction of A to B to meet the load requirements in B depending on where load management procedures are implemented.Adopted by Board of Trustees: November 1, 2006 Page 15 of 17Effective Date: October 1, 2007?An EEA 1 and a TEA 1 should be issued to identify the potential issuesBA Total Load 2,500 MWBA Total Gen 1,700 MWBAImpLimit500MWABLoad 1,500 MWLoad 1,000 MWGen available 1,600 MWGen available 100 MWImp 300 MWImp 200 MWExp 0 MWExp 0 MWInterruptible 100 MWLoadInterruptible 50 MWLoadV/R 50 MWV/R 50 MWBalancing Authority X Standard TOP-004-3 ? Transmission OperationsAdopted by Board of Trustees: November 1, 2006 Page 16 of 17Effective Date: October 1, 2007 When load management procedures are implemented to manage the transfer from A to B a TEA 2 should be issued (assumes B will be deficient before the global deficiency occurs).?An EEA 2 should be issued when load management procedures are being implemented in A to manage global requirements. TEA 3 should also be issued when Firm load is shed in B to meet the load requirements in B while respecting the IROL.Standard TOP-004-3 Transmission OperationsExample #4Transaction CurtailmentsIROL X 500 MW - A to B300 MW - B to AIntertie Limit Intertie LimitImp 300 Imp 200Exp 200 Exp 100EEA1 No2 No3 NoTEA1 No2 No3 NoIn this example there are no global adequacy concerns. There is an export transaction in B that is causing a limit concern on X in the A to B direction. With the available generation in B plus the transfer capability there is no concern for violating the IROL limit. The transaction is creating a situation where it will be required curtailed at some point to prevent the IROL violation. Assuming the TLR procedure would be effective at relieving this constraint regardless of the TLR level (at either the TLR 3 or 5 level) no TEA would be required as there is no concern that the IROL can't be respected with control actions that don't involve load management procedures.BA Total Load 2,500 MWBA Total Gen 2,500 MWBAImpLimit500MWABLoad 1,500 MWLoad 1,000 MWGen available 2,000 MWGen available 500 MWImp 200 MWImp 0 MWExp 0 MWExp 100 MWInterruptible 100 MWLoadInterruptible 50 MWLoadV/R 50 MWV/R 50 MWBalancing Authority X Adopted by Board of Trustees: November 1, 2006 Page 17 of 17Effective Date: October 1, 2007

Response: As per the wording of the attached document**: "**may be initiated only by a Reliability Coordinator' this certainly seems to say that this requirement

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belongs in the IRO family of standards as opposed to the TOP family of standards. This request should be forwarded to Project 2006-06.		
SERC OC Standards Review Group	Yes	TOP-001 R2 - The phrase "shall coordinate its respective operations known or expected to have a reliability impact on other reliability entities" could cause compliance issues due to the resulting subjectivity of the identification of other reliability entities. We recommend that it replaced with "shall coordinate its respective operations known or expected to have a reliability impact on adjacent reliability entities". It should be the responsibility of the adjacent reliability entity to further coordinate, if necessary, other appropriate reliability entities. The Measures and VSLs would need to be modified accordingly. Top-001, Requirement 4 - we suggest changing other reliability entities to adjacent reliability entities. TOP-002 R2 uses the word "plan" as a verb, and then it is referenced in R3 as a noun. This is propagated in the Measures and VSLs. We suggest the following wording change in R2: The Transmission Operator shall have a coordinated plan...... ? TOP-003 R1.2 We disagree with this requirement and we recommend that it be struck. The TOP and the BA must be able to specify formats that can be utilized by their processes to ensure reliability.
Response: The word 'coordinate' is not used in TOP-001-2, Requirement R2 but upon review the SDT has modified the wording to address your concern about affected Transmission Operators. **TOP-001-2, R2.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions. If there are known 3rd party impacts, it only makes sense that all entities need to be informed. 'Other' provides that flexibility and includes adjacent. The SDT sees no reason to change the wording in TOP-002-3, Requirements R2 & R3. Plan can be both a noun and a verb and the usage here is self-explanatory. The SDT believes that R1.2 is a reasonable attempt to solve the problem where there are 2 different system involved. Deleting the requirement doesn't solve the problem. No change made.		
Dominion Resources Inc.	Yes	TOP-001 uses the term reliability entities in the purpose statement while TOP-003 uses the term functional responsibilities. The Functional Model uses the term Responsible Entities. We suggest that NERC and the SDT make every effort to use consistent terms. We continue to have concerns with the current standards review/approval process. Having to make comments on new draft standards that are predicted upon other draft standards that have not been approved is a non-productive process.As stated in the implementation plan ?Changes made in this project

Organization	Yes or No	Question 6 Comment
		to TOP-005-1, R1; TOP-007-0, R4 are dependent on corresponding changes being approved in Project 2006-06 Reliability Coordination: COM-001-1: Telecommunications? COM-002-2: Communications and Coordination? IRO-001-1: Reliability Coordination Responsibilities and Authorities? IRO-002-1: Reliability Coordination Facilities? IRO-014-1: Procedures to Support Coordination between Reliability Coordinators? IRO-015-1: Notifications and Information Exchange between Reliability Coordinators? IRO-016-1: Coordination of Real-Time Activities between Reliability Coordinators? PER-004-1: Reliability Coordination Staffing? PRC-001-1: System Protection Coordination?
Response: The SDT has reviewed the wording indicated and sees no reason for confusion or concern and has not made any changes to these statements. The Standards Committee and NERC staff has the responsibility for coordinating multiple standards and deciding what can be posted concurrently. The SDT has no control over this.		
MRO NERC Standards Review Subcommittee	Yes	See response to question number 5 which is ?After the review of the paragraph 1612 of the FERC final order 693, the MRO NSRS would like them to be more specific about the type of outages and consistent with the Reliability Coordinator's requirement; the Reliability Coordinator has a wide-area view. How would this country-wide advance notice improve reliability for two independent systems not physically interconnected? In TOP-001-1 R1, what is a reliability directive? Should this be defined? The NERC standard COM-002-2 talks about the RC issuing a reliability directive, what is a directive? Not every communication is a directive; please clarify what is a reliability directive. Should each directive start off by stating that it's a directive and that 3 way communication should be used? (In the MISO Business Practice RTO-OP-002 R7, Telephone Communications Protocol, section 3.2.1, when issuing a Reliability Directive the following must be stated: This is a Reliability Directive and I will need you to repeat it back.) Other MISO Business Practices which discuss reliability directives are RTO-BPM-006-R2 and RTO-EOP-003-R8. The current standard TOP-002-2a includes an interpretation of R11 stating among other things that a unique study is not needed for each operating day. The MRO NSRS recommends revising the TOP-002-3 R1 to include this interpretation. For the TOP-003-1 R1, Each Transmission Operator and Balancing Authority shall have a documented specification for data to support its Real-time monitoring and reliability assessments required to fulfill their respective responsibilities per the NERC Functional Model., the MRO NSRS believes that this phrase NERC Functional Model should be removed since it is unclear as it reads now and it should be replaced with R1.1, R1.2, and R1.3.
Response: See the response to question 5.		

Organization	Yes or No	Question 6 Comment
The Reliability Coordination SDT is proposing the following as a definition of reliability directive. **Reliability Directive:** A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency, Neither the measure nor the requirement states that you must have a power flow study for each day. The measure states that you COULD have a power flow study as one method of measuring compliance. The SDT feels that this is clear and no change is necessary. The SDT agrees and has modified the requirement accordingly. **TOP-003-1, R1**. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include:		
FMPA and its All Requirements Project Participants, as follows: Kissimmee Utility Authority, City of Vero Beach, Lakeland Electric, Florida Municipal Power Pool	Yes	We generally support the revised standards, but did have a few additional comments:? The data retention is significantly longer than earlier standards, e.g., three years rather than 3 months, and the data retention is not consistent between standards, e.g., TOP-001-2 is one year, TOP-002-3 is six months, TOP-003-1 and TOP-004-3. What is your reasoning behind these changes and the inconsistencies between them? Also, saving daily operating data for three years seems a long time. TOP-002-3 R1 probably ought to refer to TOP-003-1 as one of the sources of data for the assessments. Do the standards require current day plans? TOP-002-3 and IRO-004-1 only covers next day. Are we making current day equivalent to real-time, and therefore not requiring a plan for the current day?? TOP-002-3 R1 assigns the same task to the TOP that the RC has in IRO 004 1 R1, although not as confusing as real-time operations with two entities responsible for the same thing, as discussed above in the comments to TOP-001-2, this also has potential for confusion of roles, responsibilities and actions. Should only one entity be responsible for next day plans, e.g., the RC? Or is the distinction that RCs study interfaces, whereas the TOPs assess its entire system? If so, should such a distinction exist?
Response: The SDT has changed the data retention for TOP-003-1, Requirements 2, 3, and 5 to 90 days. The SDT finds no reliability reason to specify the data sources employed in TOP-002-3. That seems more like a 'how' as opposed to a 'what'. No change made. The next day plan referenced here becomes the basis of the current day plan today. No change made. The Transmission Operator is responsible for its area and the Reliability Coordinator is responsible for theirs. The SDT sees no conflict here. No change made.		
Colmac Clarion	Yes	During 'blackout' that resulted in this program, GOP's received more intial information on problem and expected recovery from CNN then from 'chain of command'. If response is expected inclusion in information stream must also be included.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">Response: The SDT can not respond unless specific references and suggestions are provided.</td></tr>
<tr><td>Xcel Energy</td><td>Yes</td><td>In general, we appreciate the drafting team's work and feel the drafted standards are a positive move towards more simplified requirements. However, we do have some concerns, detailed below.
TOP-001>We feel the new R3 should also be applicable to BAs & GOs.
>R4 - The phrase reliability entities needs definition. It is not clear who is being referenced.
>R6 consider adding language to include SOLs.
TOP-002>R1- We assume that the use of the defined term ?Contingency? implies N-1 contingency planning. Yet, it is not clearly stated as such and therefore open to some interpretation. We recommend adding language to clarify, similar to the current version.
>R2 What is the intent here? Please clarify if planning is intended to entirely prevent the exceedence of an IROL, or to not exceed an IROL Tv.
>R3 - The phrase reliability entities needs definition. It is not clear who is being referenced.
>Deletion of the current R3 raises a concern as to what now requires LSEs and GOPs to coordinate their planning. This can present problems with TOPs and BAs attempting to collect needed data.
>Deletion of current R8 where is this covered elsewhere?
TOP-003>R1.1 long term needs more definition; we recommend changing to operating horizon
>R1.1 We do not believe it was the drafting teams intent to require outage reports of all BES components (breakers, etc), nor do we feel that is reasonable. We recommend the addition of a clarifying statement such as: BES components specified by the Transmission Operator and Balancing Authority.
>R5 uses the phrase immediate responsibility suggest changing this to responsible for real time operations.
>It is not yet clear where the current R2 and R3 are being moved to. The previous draft indicated they would be moved to IRO standards. Please provide the link to those drafts or the project they are being worked under.</td></tr>
<tr><td colspan="3">Response: TOP-001-2, R3: The obligation is on the Transmission Operator to coordinate emergency assistance and is not a task for the Balancing Authority or Generator Operator. No change made.
R4: Reliability entities are the entities certified by NERC as such. No change made.</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td colspan="3">R6: The industry is indicating approval of having this requirement limited to IROL and IROL T_v. No change made.

TOP-002-3, R1: The SDT has modified the wording to address this concern.

TOP-002-3, R1. Each Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential single Contingency events.

R2: The statement is to plan to avoid exceedances of an IROL with no timing element involved. No change made.

R3: Reliability entities are the entities certified by NERC as such. No change made.

R3: TOP-003-1 covers the data requirements. No change made.

R8: The SDT assumes you mean the current approved standard as opposed to what was posted. This was deleted because Balancing Authorities can't deliver anything. No change made.

TOP-003-1, R1.1: Long term is 'defined' by the use of the Operations Planning Time Horizon which is limited to one year.

R1.1: The SDT agrees and has changed the requirement accordingly.

TOP-003-1, R1.1, bullet #1: Long term outages of Bulk Electric System equipment, as specified by the Transmission Operator or Balancing Authority,

R5: The SDT has deleted that terminology.

TOP-003-1, R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities , the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments.

R2: This is being covered in Project 2006-06.</td></tr>
<tr><td>Ameren</td><td>Yes</td><td>The team has done a significant amount of work in getting these standards cleaned up. There was too much duplication and uncertainty.</td></tr>
<tr><td>PJM's NERC and Regional Coordination Department</td><td>Yes</td><td></td></tr>
<tr><td>PacifiCorp</td><td>Yes</td><td></td></tr>
<tr><td>WECC</td><td>Yes</td><td></td></tr>
<tr><td>NextEra Energy Resources, LLC</td><td>Yes</td><td></td></tr>
</table>

Organization	Yes or No	Question 6 Comment
American Electric Power	Yes	
E.ON U.S.	Yes	
Con Edison System Ops		No single concern. Each revision should be analyzed on its own merits.
Manitoba Hydro	Yes	
Entergy Services	Yes	
Puget Sound Energy	Yes	
Response: Thank you for your response.		

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The schedule shows completion of the project in 4Q09. The current draft is the second posting of the revised standards. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	September 2009
2. Post for re-ballot.	November 2009
3. Submit to BOT.	December 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Coordination of Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).

4. **Applicability**

    4.1. Balancing Authorities

    4.2. Transmission Operators

    4.3. Generator Operators

    4.4. Distribution Providers

    4.5. Load-Serving Entities

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued by the Transmission Operator, unless the respective entity informs the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R3. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R4. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected by the Transmission Operator to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. Such operations include, but are not limited to, relay or equipment failures and changes in generation, Transmission, Load, or operating conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R6. Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs) which, while not IROLs, support its local area reliability**.** *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations*

R7. Each Transmission Operator shall inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R8. Each Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall each make available upon request, in accordance with Requirement R1, evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and affected Transmission Operators of actual Emergency and anticipated Emergency conditions in accordance with Requirement R2. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M3. Each Transmission Operator shall make available upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R3 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. Each Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among impacted reliability entities in accordance with Requirement R4 unless conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M5. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an identified Interconnection Reliability Operating Limit (IROL) and its associated IROL T_v as specified in Requirement R5. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion outside of the identified IROL and applicable IROL T_v.

M6. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability in accordance with Requirement R6. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M7. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded in accordance with Requirement R7. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M8. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

Each Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance for each applicable Requirement R1 through R4 and R6 through R8 and Measure M1 through M4 and M6 through M8 for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement

Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v as specified in Requirement R5 and Measurement M5.

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with a Reliability Directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements.
R2	The Transmission Operator did not inform one other Transmission Operator of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform two other Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform three other Transmission Operators of an actual Emergency or anticipated Emergency conditions.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition.. OR The Transmission Operator did not inform four or more other Transmission Operators of an actual Emergency or anticipated Emergency conditions.
R3	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting entity had implemented its comparable emergency procedures and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R4	The responsible entity did not coordinate its respective operations known or expected by the Transmission Operator to impact other reliability entities with 5% or less of the affected reliability entities when conditions did permit such	The responsible entity did not coordinate its respective operations known or expected by the Transmission Operator to impact other reliability entities with more than 5% or less than or equal to 10% of the affected reliability entities when	The responsible entity did not coordinate its respective operations known or expected by the Transmission Operator to impact other reliability entities with more than 10% or less than or equal to 15% of the affected reliability entities when	The responsible entity did not coordinate its respective operations known or expected by the Transmission Operator to impact other reliability entities with more than 15% of the affected entities when conditions did permit such coordination.

	Lower	Moderate	High	Severe
	coordination.	conditions did permit such coordination.	conditions did permit such coordination.	
R5	N/A	N/A	N/A	The Transmission Operator did not operate within an identified Interconnection Reliability Operating Limit (IROL) and the associated IROL T_v for any single occasion.
R6	The Transmission Operator did not inform its Reliability Coordinator of one SOL which, while not an IROL, supports its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs which, while not IROLs, supports its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs which, while not IROLs, supports its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs which, while not IROLs, supports its local area reliability**.**
R7	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when one SOL (that supports its local area reliability) has been exceeded.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when two SOLs (that support its local area reliability) have been exceeded.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when three SOLs (that support its local area reliability) have been exceeded.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL has been exceeded OR The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when four or more SOLs (that support its local area reliability) have been exceeded..
R8	N/A	N/A	N/A	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

Standard Development Roadmap

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Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
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Future Development Plan:

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2. **Number:** TOP-001-2

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R2. Each Transmission Operator shall inform its Reliability Coordinator and ~~affected~~ other Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R3. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R4. Each Transmission Operator and Generator Operator shall coordinate its respective operations known or expected by the Transmission Operator to have a reliability impact on other reliability entities with those entities unless conditions do not permit such coordination. Such operations include, but are not limited to, relay or equipment failures and changes in generation, Transmission, Load, or operating conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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R8. ~~The~~ Each Transmission Operator shall act or direct others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

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M3. ~~The~~ Each Transmission Operator shall make available upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R3 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. ~~The~~ Each Transmission Operator and Generator Operator shall each make available upon request, evidence that operations were coordinated among impacted reliability entities in accordance with Requirement R4 unless conditions do not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M5. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an identified Interconnection Reliability Operating Limit (IROL) and its associated IROL T_v as specified in Requirement R5. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion outside of the identified IROL and applicable IROL T_v.

M6. ~~The~~Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of all SOLs which, while not IROLs, support its local area reliability in accordance with Requirement R6. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M7. ~~The~~ Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded in accordance with Requirement R~~5~~7. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M8. ~~The~~ Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v in accordance with Requirement R~~6~~8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable.

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

~~The~~ Each Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance for each applicable Requirement R1 through R4 and R6 through R8 and Measure M1 through M4 and M6 through M8 for the current calendar year and one previous calendar year unless directed by its Compliance

Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

~~The~~Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v as specified in Requirement R5 and Measurement M5.

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The ~~Balancing Authority, Distribution Provider, Load-Serving Entity, or Generator Operator~~ responsible entity did not comply with a ~~r~~Reliability ~~d~~Directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements.
R2	The Transmission Operator did not inform ~~its Reliability Coordinator and~~ one affected other Transmission Operator~~s~~ of an actual Emergency ~~and~~ or anticipated Emergency conditions ~~on one occasion~~.	The Transmission Operator did not inform ~~its Reliability Coordinator and~~ two affected other Transmission Operators of an actual Emergency ~~and~~ or anticipated Emergency conditions ~~on two occasions~~.	The Transmission Operator did not inform ~~its Reliability Coordinator and~~ three affected other Transmission Operators of an actual Emergency ~~and~~ or anticipated Emergency conditions ~~on three occasions~~.	The Transmission Operator did not inform its Reliability Coordinator ~~and affected Transmission Operators~~ of an actual Emergency ~~and~~ or an anticipated Emergency condition~~s~~. ~~on four or more occasions~~. OR The Transmission Operator did not inform four or more other Transmission Operators of an actual Emergency or anticipated Emergency conditions.
R3	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission

	Lower	Moderate	High	Severe
				Operators, as requested and available, ~~provided that~~when the requesting entity ~~has~~had implemented its comparable emergency procedures and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R4	The ~~Transmission Operator or Generator Operator~~ responsible entity did not coordinate ~~their~~ its respective operations known or expected by the Transmission Operator to impact other reliability entities with ~~2~~5% or less of the affected reliability entities ~~unless~~ when conditions did ~~not~~ permit such coordination.	The ~~Transmission Operator or Generator Operator~~ responsible entity did not coordinate ~~their~~ its respective operations known or expected by the Transmission Operator to impact other reliability entities with more than ~~2~~5% or less than or equal to ~~5~~10% of the affected reliability entities ~~unless~~ when conditions did ~~not~~ permit such coordination.	The ~~Transmission Operator or Generator Operator~~ responsible entity did not coordinate ~~their~~ its respective operations known or expected by the Transmission Operator to impact other reliability entities with more than ~~5~~10% or less than or equal to ~~7~~15% of the affected reliability entities ~~unless~~ when conditions did ~~not~~ permit such coordination.	The ~~Transmission Operator or Generator Operator~~ responsible entity did not coordinate ~~their~~ its respective operations known or expected by the Transmission Operator to impact other reliability entities with more than ~~7~~15% of the affected entities ~~unless~~ when conditions did ~~not~~ permit such coordination.
R5	N/A	N/A	N/A	The Transmission Operator did not operate within an identified Interconnection Reliability Operating Limit (IROL) and the associated IROL T_v for any single occasion.
R6	The Transmission Operator did not inform its Reliability Coordinator of one SOL which, while not an IROL, supports its local area reliability.	The Transmission Operator did not inform its Reliability Coordinator of two SOLs which, while not IROLs, supports its local area	The Transmission Operator did not inform its Reliability Coordinator of three SOLs which, while not IROLs, supports its local area	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs which, while not IROLs, supports its local area

	Lower	Moderate	High	Severe
		reliability.	reliability.	reliability.
R~~5~~7	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when ~~an~~one ~~IROL or~~ SOL (that supports its local area reliability) has been exceeded ~~on one occasion~~.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when ~~an~~two ~~IROL or~~ SOLs (that support its local area reliability) ~~has~~have been exceeded ~~on two occasions~~.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when ~~an~~three ~~IROL or~~ SOLs ~~has~~(that support its local area reliability) have been exceeded ~~on three occasions~~.	The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL ~~or SOL~~ has been exceeded ~~on four or more occasions~~ OR The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when four or more SOLs (that support its local area reliability) have been exceeded..
R~~6~~8	~~The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's~~ ~~T_v~~ ~~on one occasion.~~ N/A	~~The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's~~ ~~T_v~~ ~~on two occasions.~~ N/A	~~The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's~~ ~~T_v~~ ~~on three occasions.~~ N/A	The Transmission Operator did not make available evidence of its actions or when it directed others to act, to mitigate the magnitude and duration of exceeding an IROL within the IROL's T_v, ~~on four or more occasions~~.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	September 2009
2. Post for re-ballot.	November 2009
3. Submit to BOT.	December 2009

Definitions of Terms Used in Standard

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**
2. **Number:** TOP-002-3
3. **Purpose:** To ensure that reliability entities have coordinated plans for meeting expected operating conditions.
4. **Applicability**

   4.1. Transmission Operator.
5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential single Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) identified as a result of the assessment performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of an assessment for next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has planned to preclude operating in excess of the IROLs identified as a result of the assessment performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL.

M3. Each Transmission Operator shall make available evidence that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator does not have an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and potential single Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of those IROLs identified as a result of the assessment performed in Requirement R1.
R3	The Transmission Operator did not notify 5% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify more than 5% and less than or equal to 10% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 10% and less than or equal to 15% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than 15% of the reliability entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

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0	April 1, 2005	Effective Date	New
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Future Development Plan:

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that reliability entities have coordinated plans for meeting expected operating conditions.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. ~~The~~ Each Transmission Operator shall have an assessment for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs) during anticipated normal conditions and potential single Contingency events. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. ~~The~~ Each Transmission Operator shall plan to preclude operating in excess of ~~any~~ those Interconnection Reliability Operating Limits (IROLs) ~~including those~~ identified as a result of the assessment performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

R3. ~~The~~ Each Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

C. Measures

M1. ~~The~~ Each Transmission Operator shall have evidence ~~that it has assessed~~ of an assessment for next day operations in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

M2. ~~The~~ Each Transmission Operator shall have evidence that it has planned to preclude operating in excess of the IROLs identified as a result of the assessment performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL.

M3. ~~The~~ Each Transmission Operator shall make available evidence that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Reset Time Frame

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

~~The~~ Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator ~~did not perform~~ does not have an assessment for the next day's operation that indicated whether it will exceed any of its SOLs during anticipated normal and potential single Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of ~~any~~ those IROLs identified as a result of the assessment performed in Requirement R1.
R3	The Transmission Operator did not notify ~~2~~5% or less of the reliability entities identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify more than ~~2~~5% and less than or equal to ~~5~~10% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than ~~5~~10% and less than or equal to ~~7~~15% of the reliability entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify more than ~~7~~15% of the reliability entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

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Future Development Plan:

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1. Post for ballot.	September 2009
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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**
2. **Number:** TOP-003-2
3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.
4. **Applicability**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
   - **4.3.** Generator Owners.
   - **4.4.** Generator Operators.
   - **4.5.** Interchange Authorities.
   - **4.6.** Load-Serving Entities.
   - **4.7.** Transmission Owners.
5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of required data to be exchanged including, but not limited to:

- Long term outages of Bulk Electric System equipment, as specified by the Transmission Operator or Balancing Authority, .
- Equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.

1.2. A mutually agreeable format.

1.3. A timeframe and periodicity for providing data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R1.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for data necessary for Real-time monitoring and reliability assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall retain evidence for 90 calendar days that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4 and Measurement M4.
- Each Transmission Operator and Balancing Authority shall retain evidence for 90 calendar days that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities

necessary for reliability assessments and Real-Time operations in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The responsible entity did not have one of the required elements of the documented specification for data necessary for Real-time monitoring and reliability assessments.	The responsible entity did not have two of the required elements of the documented specification for data necessary for Real-time monitoring and reliability assessments.	N/A	The responsible entity did not have a documented specification for data necessary for Real-time monitoring and reliability assessments.
R2	The Transmission Operator did not distribute its data specification to 5% or less of the entities that has Facilities monitored by the Transmission Operator or to 5% or less of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 5% and less than or equal to10% of the entities that have Facilities monitored by the Transmission Operator or to more than 5% and less than or equal to 10% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 10% and less than or equal to 15% of the entities that have Facilities monitored by the Transmission Operator or more than 10% and less than or equal to 15% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than 15% of the entities that have Facilities monitored by the Transmission Operator or more than 15% of the entities that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to 5% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 5% and less than or equal to 10% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 10% and less than or equal to 15% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than 15% of the entities that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R2 or R3 did not satisfy the obligations of the documented specifications for data. .
R5	N/A	N/A	N/A	The responsible entity did not provide to other Transmission Operators or Balancing Authorities the data and information requested by those entities necessary for real-time monitoring and reliability assessments.

E. Regional Variances

None identified.

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7. Second posting of revised standards on April 7, 2009.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008 following the approval of the SAR by the SC. The schedule shows completion of the project in 4Q09. The current draft is the second posting of the revised standards. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	September 2009
2. Post for re-ballot.	November 2009
3. Submit to BOT.	December 2009

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-~~1~~2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Owners.

   4.4. Generator Operators.

   4.5. Interchange Authorities.

   4.6. Load-Serving Entities.

   4.7. Transmission Owners.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for data necessary for Real-time monitoring and reliability assessments~~required to fulfill their respective responsibilities per the NERC Functional Model~~. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

~~R1.1.~~1.1. A list of required data to be exchanged including, but not limited to:

- Long term outages of Bulk Electric System equipment, as specified by the Transmission Operator or Balancing Authority, ~~when they are known,~~.
- Equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.

~~R1.2.~~1.2. A mutually agreeable format.

~~R1.3.~~1.3. A timeframe and periodicity for providing data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. ~~provide data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies)~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning~~, Same-day Operations, Real-Time Operations~~]*

~~C.~~R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities ~~with immediate responsibility for operational reliability~~, the data requested by those other Transmission Operators and Balancing Authorities necessary for Real-time monitoring and reliability assessments. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R1.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data ~~provided data, as specified in Requirement R1, to its Transmission Operator(s) and Balancing Authority(ies)~~ in accordance with Requirement R4. ~~The data is limited to that needed by the Transmission Operator to support Operational Planning Analyses and reliability assessments. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.~~ The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities ~~with~~

~~immediate responsibility for operational reliability,~~ the data requested by those entities necessary for reliability assessments and Real-time operation in accordance with Requirement R5. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not applicable

1.3. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for data necessary for Real-time monitoring and reliability assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall retain

evidence for ~~three~~90 calendar ~~years~~days that it has satisfied the obligations of the documented specifications for data ~~provided data, as specified in Requirement R1to its Transmission Operator(s) and Balancing Authority(ies)~~ in accordance with Requirement R4 and Measurement M4.

- Each Transmission Operator and Balancing Authority shall retain evidence for ~~three~~90 calendar ~~years~~days that it has provided to other Transmission Operators and Balancing Authorities ~~with immediate responsibility for operational reliability,~~ the data requested by those entities necessary for reliability assessments and Real-Time operations in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.5. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The ~~Transmission Operator or Balancing Authority~~ responsible entity did not have one of the required elements of the documented specification for data necessary for Real-time monitoring and reliability assessments.	The ~~Transmission Operator or Balancing Authority~~ responsible entity did not have two of the required elements of the documented specification for data necessary for Real-time monitoring and reliability assessments.	N/A	The ~~Transmission Operator or Balancing Authority~~ responsible entity did not have a documented specification for data necessary for Real-time monitoring and reliability assessments.
R2	The Transmission Operator did not distribute its data specification to ~~2~~5% or less of the entities that has Facilities monitored by the Transmission Operator or to ~~2~~5% or less of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than ~~2~~5% and less than or equal to~~5~~10% of the entities that have Facilities monitored by the Transmission Operator or to more than ~~2~~5% and less than or equal to ~~5~~10% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than ~~5~~10% and less than or equal to ~~7~~15% of the entities that have Facilities monitored by the Transmission Operator or more than ~~5~~10% and less than or equal to ~~7~~15% of the entities that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to more than ~~7~~15% of the entities that have Facilities monitored by the Transmission Operator or more than ~~7~~15% of the entities that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to ~~2~~5% or less of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than ~~2~~5% and less than or equal to ~~5~~10% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than ~~5~~10% and less than or equal to ~~7~~15% of the entities that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to more than ~~7~~15% of the entities that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The ~~Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, or Transmission Owner~~ responsible entity receiving a data specification in Requirement R2 or R3 did not satisfy the obligations of the documented specifications for data. ~~provide data and information, as specified in~~

				~~Requirement R1, to its Transmission Operator(s) or Balancing Authority(ies)~~.
R5	N/A	N/A	N/A	The ~~Transmission Operator or Balancing Authority~~ responsible entity did not provide to other Transmission Operators or Balancing Authorities ~~with immediate responsibility for operational reliability,~~ the data and information requested by those entities necessary for real-time monitoring and reliability assessments.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form for Third Draft of Standards for Real-Time Operations (Project 2007-03)

Please **DO NOT** use this comment form. Please use the electronic comment form located at the link below to submit comments on the third draft of the standards for Real-Time Operations (Project 2007-03). Comments must be submitted by **September 24, 2009**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Background Information:
In the 3rd posting for Project 2007-03, the Real-Time Operations Standard Drafting Team (RTO SDT) has attempted to clarify the proposed changes to the TOP family of standards based on industry comments received for the 2nd posting.

***Please use the electronic comment form to submit your final responses to NERC.**

1. TOP-001-2: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

   ☐ Yes
   ☐ No
   Comments:

2. TOP-002-3: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

   ☐ Yes
   ☐ No
   Comments:

3. TOP-003-1: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

   ☐ Yes
   ☐ No
   Comments:

4. TOP-004-3: Do you agree with the decision to move the lone remaining requirement of this standard to TOP-001-2? If not, please supply specific reasons why you do not agree with this move.

   ☐ Yes
   ☐ No
   Comments:

5. TOP-001-2, Requirement R1: Do you believe that the Balancing Authority issues Reliability Directives directly for transmission-related limits and therefore should be in the TOP standards,(vote YES); or do you believe that the Balancing Authority in its role as a Balancing Authority issues Reliability Directives to balance load and generation and only indirectly affects transmission flows (recognizing that an entity that serves as both a Transmission Operator and a Balancing Authority would be covered under the Transmission Operator requirement) (Vote NO). Please be as specific as possible with your reply.

   ☐ Yes
   ☐ No
   Comments:

6. Do you agree that with the changes in the 3rd posting that this project is ready to go to ballot? If not, please supply specific reasons why not.

   ☐ Yes
   ☐ No
   Comments:

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RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
August 25–September 24, 2009

Now available at: http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Project Name
2007-03 — Real-time Operations Standards

Due Date and Submittal Information
The comment period is open **until 8 p.m. EDT on September 24, 2009**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Content for Comment Period
The Real-time Operations Standards Drafting Team is seeking comments on its revised drafts of the following proposed standards:

- TOP-001-2 — Reliability Responsibilities and Authorities
- TOP-002-3 — Normal Operations Planning TOP-003-2 — Planned Outage Coordination

Other Materials Posted
The drafting team's consideration of industry comments received during the previous comment period

Project Background
The drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. In addition, the drafting team has supplied a complete set of Violation Risk Factors, time horizons, measures, and compliance elements including Violation Severity Levels. An implementation plan has been provided to show the timeframe for compliance.

Applicability of Standards in Project
Transmission Operator
Transmission Owner
Balancing Authority
Generator Owner
Generator Operator
Interchange Authority
Load-Serving Entity
Distribution Provider

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Name (15 Responses)
Organization (15 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
Question 1 (24 Responses)
Question 1 Comments (26 Responses)
Question 2 (25 Responses)
Question 2 Comments (26 Responses)
Question 3 (24 Responses)
Question 3 Comments (26 Responses)
Question 4 (24 Responses)
Question 4 Comments (26 Responses)
Question 5 (23 Responses)
Question 5 Comments (26 Responses)
Question 6 (23 Responses)
Question 6 Comments (26 Responses)

Individual
James A Maenner
James A Maenner
Yes
Yes
Yes
Yes
No
BAs that neither own nor operate transmission should not issue reliability directives for transmission-related limits. Without the tools and knowledge of a Transmission Operator, the BA could isssue conflicting orders to the TOP's operating plans. Certainly, the BA should relay a TOP directive but not be the initiator.
Yes
Group
Northeast Power Coordinating Council
Guy Zito
No
(1) In R1, reliability directive is capitalized in indicating (or implying) it is a defined term. But this term has not yet been defined despite our understanding that there are currently three SDTs that are reviewing and/or attempting to define this term and the term (Directive). We suggest to make this term lower case until it is defined. (2) R2: the revised wording seems a bit odd as the phrase “expected to be affected” could be interpreted to be describing the actual or anticipated Emergency conditions. We suggest R2 to be revised to: “Each Transmission Operator shall inform its Reliability Coordinator and known or expected to be affected Transmission Operators of actual Emergency and anticipated Emergency conditions” to enhance clarity. Alternatively, we propose inserting a comma after “expected to be affected”. (3) R3: Add a comma after “…comparable emergency procedures”. (4)Similar to their IROL counterparts, operating within all SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations. (5) As pointed out in our previous comments, we did not agree that VSLs should be determined based on the number of times a requirement was violated. While it is appropriate to determine the VSLs for R6 based on the number of SOLs that support local area reliability not reported to the RC since these numbers

represent the extent of missing the total set, the same approach should not be applied to the determination of R7 since the progressive VSLs appear to make a difference between IROL and SOL(Note: the former has a Severe VSL for failing to notify one exceedance whereas for the latter the VSLs are graded based on the number of SOLs whose exceedances a TOP failed to notify its RC). Note that R7 requires that the TOP inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. The requirement does not make any distinction between IROL and SOL, and requires that there shall not be even a single incident that the TOP does not inform its RC of actions being taken to mitigate an IROL or SOL exceedance. Hence, missing even one SOL would violate the bulk of the intent of R7. We suggest the VSLs for Low, Moderate and High be removed, and revise the VSL for Severe to: The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limit when an IROL or SOL has been exceeded.
No
(1) We continue to disagree with the way R2 is worded. R1 requires a TOP to conduct next day analysis to assess if any of the SOLs will be exceeded. R2 requires that the TOP develop plans to preclude operating in excess of only the IROLs identified as a result of the assessment performed in R1. Given our stance on this issue and understanding that IROLs represent a subset of SOLs, we believe R2 should be changed to SOL. In our view, a TOP needs to conduct next day analysis to assess if any of the established limits will be exceeded, develop plans to preclude operating in excess of the IROLs and SOLs, and make resources and actions available for mitigating exceedances if and when they occur. Like operating within SOLs and IROLs, this is fundamental to reliable operation. We suggest R2 be revised to include all SOLs. Remove “single” from R1.
Yes
Regarding R4, M4, it does not appear to be warranted that a Generator Owner, Generator Operator, Interchange Authority, or Load-Serving Entity provide evidence that there are no outstanding requests for data. As the originator of the request, the evidence that there are no outstanding requests for data should be provided by the Balancing Authority or Transmission Operator, as applicable.
Yes
No
The BA’s role is to balance load-generation-interchange and does not have any direct role in monitoring and operating system conditions within transmission-related limits.
No
We continue to strongly disagree with removing the requirements for a TOP to plan and make day ahead arrangement for operating with all SOLs, and during day at hand and real time operate the system within established SOLs (and IROLs) and mitigate SOL exceedances within a predetermined time period. These are the most critical tasks for the TOPs, and are fundamental to ensuring reliability. We are unable to support these standards if the necessary requirements are not reinstated/revised (as suggested in Q1 to change R5 of TOP-001 and in Q2 to change R1 and R2 of TOP-002). R6 should be reworded to read "Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs)which, while not IROLs, support its Transmission Operator area reliability.
Individual
Kasia Mihalchuk
Manitoba Hydro
No
R.4 - The changes suggested to R. 4 are too vague to result in effective coordination. What is meant by “expected relay failures”? How is an expected relay failure assessed? What criteria is used to determine what we consider a risk of an expected relay failure - what conditions? R.6 - is again too vague for making consistent operating decisions. What criteria is applied for identifying SOL’s that support “local area reliability”? What is a local area, how large is it, what reliability criteria is violated on the violation of an SOL? R.7 - SOL’s identified in R6 are vague.
Yes

Yes
Yes
No
The BA is responsible to operate its generation assets within the reliability constraints established by the Transmission Operator and Reliability Coordinator.
No
Changes are still required to TOP-001-2
Group
WECC RC
Michael Davis
No
What is definition for when an SOL supports or does not support Local Area Reliabilty? Is this for 100kV and above? What are the timing requirements for returning elements to a level below their SOL?
No
R2 should include SOLs. In R3 the plan should be shared with the RC.
No
Is mutually agreeable a formal process? Should it be in writing? The RC should be involved because of the numerous formats it has to deal with.
Yes
No
In WECC, the RC deals mainly with the BAs. The BAs with their responsibility to maintain load and resources, ACE, and frequency places them in a position to direct and control all other activities on the interconnection. The RC expects the BAs to accomplish and direct actions to restore or mitigate contingencies in the interconnection.
No
See previous comments.
Individual
Ed Stein
self
No
I do agree with most every thing However I do not understand what is meant by the phrase "expected to affect" a TO. How does the TO experiencing the emergency know if his emergency affect every TO. Granted he should know of the main ones but can he be sure that a remote line is affected that has a 2-5% response factor.
Yes
Yes
Yes
Yes
No
Due to my earlier response
Individual

Michael Ayotte
ITC Holdings
No
In R2, strike the words “known or”. In R4, remove the added words “by the Transmission Operator” from the second sentence . The addition of this phrase implies that the Generator Operator does have the obligation to initiate the coordination of changes in generation with the transmission operator. The requirement is clearer without this phrase. In R4, change the wording to “Such operations MAY include…” We believe the intent of the sentence was only to provide a list of examples. R6 requires the TOP to identify a sub-set of SOLs that is larger than IROLS and “support its local area reliability”. It is unclear what criteria a TOP would use to identify this subset, which will lead to inconsistent implementation and confusion. The TOP should inform the RC of all SOLs and the actions being taken to address any SOL exceedance which can be accomplished via SCADA or other means of action and communication when necessary. The measures for R5 and R8 need to be clear that these are event driven requirements and only evidence is required if an “event” has occurred.
Yes
Yes
Yes
No
Balancing Authorities do not operate transmission. They would only issue requirements with regard to capacity and energy emergencies.
No
The comments on TOP-001-2, particularly in regard to R6, need to be resolved before balloting.
Individual
Mike Gentry
Salt River Project
Yes
No
Yes
Yes
Yes
Individual
Ed Davis
Entergy Services, Inc
Yes
This standard seems to conflict with MOD-001, Requirement 7. This standard requires that: When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. When applying the requirements from TOP-002-3 along with the MOD-001 standard, it seems that all TSP’s will need to calculate ATC or AFC up to the calculated IROL for the time period. When the two standards are looked at independently they are fine, when you look at both, there is some confusion on where NERC wants

the TSP’s to go.
Group
Electric Market Policy
Jalal Babik
No
R1 - By capitalizing the term ‘Reliability Directive”, the SDT introduced a discrepancy as this term does not currently exist in the NERC Glossary of Terms. We are opposed to approving revisions to existing or new standards when they are predicated upon references to other ‘draft’ terms, standards, requirements, etc. R4 – We have reviewed the various comments made concerning retention of GOP in this requirement, and philosophically agree but find it impossible to determine how GOP can coordinate” its respective operations known or expected by the Transmission Operator to have a reliability impact….” without knowing what constitutes “expected to have a reliability impact”. The GOP can only coordinate to the extent the TOP has provided predefined information that is required to be coordinated. This information should be included in the Interconnection Agreement or some other agreement that clearly spells out what the GOP is expected to communicate in order to coordinate. We would prefer inclusion of this requirement in TOP-003 as part of R4 (referencing R2 and R3) or we could support the requirement in TOP-001 if it referenced coordination of data required in TOP-003 @ R2 and R3. Also the statement”operating conditions” is sufficiently vague. The SDT needs to clarify what constitutes an operating condition?
Yes
Yes
Yes
No
No
See comments above
Individual
Larry Watt
Lakeland Electric
Yes
Yes
Requirement R-1 and Measure M-1 require modification for clarity. Replacing the undefined term “assessment” with the NERC defined term “Operational Planning Assessment” throughout the TOP-002-3 standard will help to clarify both line items. Using “Operational Planning Analysis” in measure M-1 clarifies that the power flow study does not have to be performed day-ahead (see the definition of Operational Planning Analysis). This is in-line with the recent interpretation issued by NERC discussed in the appendix of TOP-002-2a. Using “Operational Planning Analysis” in requirement R-1 ensures the planner understands that his or her assessment is meant to be more than just a determination of System Operating Limits. Requirement R-1 would also benefit from clarifying “single Contingency event.” Current day-ahead contingency analysis is limited to determining system performance during single transmission line, generator and transformer outages. However, using “single Contingency event” could include lightning struck towers with two or more transmission lines or even bus failures at which multiple transmission lines terminate. Unless it is the intent of the standard team to increase the scope of TOP-002 I recommend finishing requirement R-1 with “. . . involving transmission lines, transformers, and generators.”

Yes
Yes
Yes
Yes
Individual
Daniel Herring
The Detroit Edison Company
Yes
Yes
Yes
Yes
No
We believe that the Balancing Authority in its role as a Balancing Authority issues Reliability Directives to balance load and generation and only indirectly affects transmission flows and should not be in the TOP standards.
Yes
Group
Southern Company
Hugh Francis
No
The measure for R2 does not carry forth the definition of which other TOP should be informed. R2 requires informing other TOPs that are expected to be affected. The measurement requires that contact was made with all TOPs that were affected. The list of TOPs that are expected to be affected before the fact may be different than the list of TOPs that actually were affected. Would suggest minor change in R2 from “Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions” to “Transmission Operators known or expected to be affected of actual Emergency or anticipated Emergency conditions” The second “each” in M1 and M4 should be deleted. Would suggest modifying VSL for M5 to read in the same tense of the Measure. Specifically, instead of “The Transmission Operator did not operate within an identified” to “The Transmission Operator operated outside an identified”
Yes
No
R1 is written for the Operations Planning timeframe. As such, would suggest rewording “shall have a documented specification for data necessary for Real-time monitoring and reliability assessments” to “shall have a documented specification for data necessary for reliability assessments and Real-time monitoring”. Having “Real-time monitoring” mentioned first may convey the impression that “Real-time” also applies to the reliability assessments. Also, would suggest rewording “Equipment at voltage levels lower than” to “Outages of equipment at voltage levels lower than.”
Yes
No

TOP-001-2 does not mention any entity except for the Transmission Operator as issuing Reliability Directives. Yes, it is appropriate for the Balancing Authority to issue Reliability Directives that are related to his responsibilities (issues regarding balance load and generation), but there should be no confusion that the Reliability Coordinator has ultimate authority and thus could issues overriding Reliability Directives. The definition of a Balancing Authority in the NERC Glossary is, "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." This definition gives them no responsibility for transmission limits. However, the Balancing Authority does need to be able to give Reliability Directives in order to aid in the resolution of transmission-related limit problems.
Additional clarification per our previous comments is required. Re-posting may not be required.
Individual
Howard Rulf
We Energies
No
We Energies joined MISO's comments for this project. We have one additional comment for this question. The BA may need to issue Directives to Generator Operators or Distribution Providers in response to a TOP or RC need to resolve a transmission issue. Basically "pass-through" the Directive from the TOP or RC to the entity that will actually carry out the directed action.
Group
SERC OC Standards Review Group
Gerald Beckerle, Vice Chair - SERC Operating Committee
No
Is Reliability Directive a defined term since it is capitalized in R1 and throughout the Standard, but not currently found in the NERC Glossary of Terms. R2 – We suggest that “other transmission operators” should be changed to “adjacent transmission operators”. R3 – What is specifically meant by the words, “emergency assistance”? For example, do the words as written require a utility to provide line crews to assist in storm restoration? We suggest that the language be tightened up to focus emergency assistance on those things that were intended by the language. R4 – we suggest removing “and Generator Operator” and the term “by the Transmission Operator” from the first sentence. It appears that the original wording implies that the Generator Operator would have knowledge of conditions on the transmission system. We also suggest removing the last sentence – listing some but not all items that may have operating impacts and in which communications is necessary, concerns the SERC OC Standards Review Group. R6 – We suggest revising R6 to read: Each Transmission Operator shall inform its Reliability Coordinator of any System Operating Limits (SOLs) which, while not IROLs, will require mitigating actions if exceeded. The current word “all” seems to indicate that every SOL would be in this list. R8 – Why is R8 needed – it appears to be a duplication of R5 and the two could be combined. General comment on measures: Measures that are event driven need to be clear that evidence would only be required if an event occurred. That is, the entity should not have to prove a negative.
Yes
No
R1 – Does “specification for data” mean a complete listing of data points or a listing of types of data required for different types of facilities such as “generation, transmission, etc.” Also, does this standard apply solely to internal requirements of a BA and its TOP? The concern is the multiple types of formats that may be required in order to exchange data with an expanded list of entities external to the BA or TOP. M5 measurements should be modeled similar to the measurement in M4, in particular, that last sentence of M4. Is TOP-003-2 a new standard utilizing an existing number? If so,

does the previous TOP-003-1, Planned Outage Coordination have to be retired? The migration from the current TOP-003-1 to the new TOP-003-2 seems like it could cause confusion. Would it be better to just retire TOP-003-1 and form a new standard number like TOP-011-1? R4 and R5: Should there be a time requirement for complying with a data request?
Yes
We are unsure how to respond to this question as it pertains to TOP-001-2, R1.
No
See the above comments. Note: The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Group
IRC Standards Review Committee
Ben Li
No
Requirement 1: Reliability Directive, as a defined term has been introduced and the definition has not been provided in this posting. If the intent is to use this as a defined term anticipating that it will be defined and approved soon under a different project, then we suggest these standards not be put up for balloting until the term is approved.
No
Requirement #1: It is not clear why we introduce 'single' Contingency event since a TOP may be required to study multiple contingencies identified by its RC (See FAC-011-2, Requirement R3). A better term may be "Contineg‍ency events identified in FAC-011."
Yes
Yes
No
The BA’s role is to balance load-generation-interchange only; it does not have any direct role in monitoring and operating system conditions within transmission-related limits.
No
(1) The SRC is concerned that the absence of an explicit requirement for operating within SOLs may be problematic. Operating within SOLs is an important operating practice that will position the system to be stable within the acceptable reliability criteria included in the definition of SOLs and the requirements to be included in the methodology that is used to determine SOLs. The SRC recognizes that SOLs cover the full range from minor localized limits through Interconnection Operating Reliability Limits (IROLs), and that SOLs are defined to respect the facility and equipment ratings that are included in the determination of the values of SOLs. The suggested requirement R6 in TOP-001-2 for a TOP to identify SOLs, for which the TOP is to notify the RC when the SOLs are exceeded, is intended to address those SOLs that, while not meeting the definition of IROLs, may have potential impact that is important from a local viewpoint. Although these SOLs may not cause an impact equivalent to or greater than that in the definition of Adverse Reliability Impact, they deserve additional attention, including monitoring and notifications between TOPs and RCs. If the SDT holds the view that operating within the identified SOLs and correcting their exceedances are implicit and precursory to R7 and R8, then we would suggest to make it explicit by revising R5, by saying, for example: R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL Tv, and each System Operating Limit (SOL) as identified in R6 and its associated time period as determined by the TOP. Similar to their IROL counterparts, operating within SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations, although for IROLs the interconnected system impact is readily obvious compared to the SOLs. The same principle holds true for day-ahead operational planning so that the needed control measures can be identified and made available in advance to prevent operating in excess of SOLs and to mitigate exceedances if and when they occur during day at hand and real-time operations. To this end, we suggest the SDT consider revising R2 of

TOP-002-3 to: "Each Transmission Operator shall plan to preclude operating in excess of those System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) identified as a result of the assessment performed in Requirement R1." (2) Also there is concern that a definition for Reliability Directive has not been determined and agreed upon through the standards development process. Until such time that the definition of Reliability Directive can be developed and agreed to, the references to Reliability Directives or these standards should not go to ballot.
Group
FirstEnergy
Sam Ciccone
No
R3 – This requirement requires "comparable emergency procedures" be implemented which is appropriate and consistent with the previous standards, but it lacks, and the previous standards lacked, the concept of mitigation. An entity should not be required to shed load for the sake of requiring a neighboring entity to shed load to mitigate the emergency condition. As currently written, in order for an entity to require its neighbor to shed load that will mitigate the emergency condition, the requesting entity is required to shed load first. We suggest this be revised to say, "comparable emergency procedures that mitigate (lessen or eliminate) the impact of the emergency." R6 – This requirement is ambiguous. By definition a System Operating Limit is "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: (a) ♣ Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings) ♣ Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits) ♣ Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability) ♣ System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)" As written, the TOP will be required to inform the RC of all equipment ratings that "support local area reliability." This could be interpreted as requiring an entity to report equipment ratings for facilities operated at 100 kV or less which we believe is not the intent of the SDT. These facilities certainly support local area reliability on some level but are not monitored by the RC and serve little or no value to the RC. FAC-014-2 requires the TOP in Req. R2 to "establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." Therefore, it appears that TOP-001-2 Req. R6 may not be necessary. However, if the intent of FAC-014-2 Req. R2 is to establish SOLs from an Operations PLANNING horizon (not sure since FAC-014-2 does not include time horizons with the requirements), and the intent of TOP-001-2 Req. R6 is to inform the RC from a REAL-TIME operations horizon, then Req. R6 of TOP-001-2 should be consistent with FAC-014 and written as follows: "R6. Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs) which are consistent with its Reliability Coordinator's SOL methodology."
Yes
Yes
We agree with the changes to TOP-003-1. However, we feel that R3 should be re-written to be consistent with the wording in R2. We suggest a change as follows: "R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority."
Yes
Yes
The question as written is confusing based on the present wording of TOP-001-2 R1. Nevertheless, we believe that the Balancing Authority (BA) should be applicable in the TOP-001-2 standard and that their role as stated in R1 is correct. The BA receives direction from the TOP when redispatch solutions are needed to alleviate transmission-related limits (i.e. voltage, thermal, etc).
No
We feel that the current draft still has issues to be addressed before balloting begins (see our comments on Questions 1 through 5). Also, we provide the following additional comments: 1. The mapping of all the requirements and standards associated with this project provided within the

Implementation Plan during the first posting is a valuable tool for industry personnel in charge of tracking compliance. However, this mapping matrix now appears to be removed from the implementation plan. We feel that the team and/or NERC should provide a revised mapping document during the next posting of documents for this project so that industry can review it. Then it should be retained as a reference tool for industry when transitioning their compliance documentation from the current standards to the new standards. 2. The implementation plan currently states: "The assumption used by the SDT in establishing this Implementation Plan is that the project mentioned in the prerequisites: Project 2006-06, Reliability Coordination; has been approved prior to the implementation of this Project 2007-03, Real-Time Operations." It should be clear that the implementation clock for these Real-Time Operations standards starts only after "applicable regulatory approval" of the standards associated with Project 2006-06.
Individual
James H. Sorrels, Jr.
American Electric Power
No
It’s our understanding that a definition of the term for a Reliability Directive (RD) may be currently under development/review/approval. However, since RD is not currently found in the NERC glossary, we request that it be added to the definition section of this standard. For example, are base points issued by the market area of an RTO considered an RD? Is there a method to distinguish such base points as constituting an RD from those that are not RDs? The team correctly capitalizes “Transmission” and “Load” since they are terms included in the NERC dictionary and does not capitalize “generation” since it is not included. It would seem that adding the term to NERC glossary would be the best resolution, but, in the interim, it should be well defined within the context that it is being used in any requirement (refer to R4). We are concerned that R5 is a duplication of a requirement in FAC-009 and perhaps others as well. Correspondingly, M5 would also be duplicative. Again, it appears that R6 may be duplicative of FAC-014, R5.2. If not, the phrase “support its local area reliability” should be clarified. While we appreciate the team’s efforts to better distinguish IROLs from SOLs in R7., more work is necessary to better define the difference. (e.g., exceeding limits vs. n-1)
Yes
Yes
AEP would appreciate that the reference to “Long term outages” in R1.1.1. be specified in terms of the time elapsed.
Yes
Yes
Even in conditions where the BA is providing RDs to balance load and generation, the changes may still impact the BES. Under such circumstances, there remains a need for the BA to be aware of loadings on the BES.
No
AEP believes that one more draft is needed to verify that key edits provided by stakeholders during this round are included before proceeding to ballot.
Individual
Greg Rowland
Duke Energy
No
• The definition of “Reliability Directive” drafted by the Reliability Coordination SDT should also be commented on in this TOP effort. We are concerned that the definition is too broad and would encompass what we consider normal communications. A key point of the definition should be that each communication of a Reliability Directive is required to be identified as such to the receiving entity. • R2 should say that the TOP shall inform its RC and direct interconnected TOPs. The phrase “known or expected to be affected” opens the TOP to non-compliance if they don’t expect someone to be affected, and it turns out that they are affected. • R3 – strike the phrase “provided that the

requesting entity has implemented its comparable emergency procedures". In this situation we should not be wasting time getting proof that the requester has implemented their procedures before rendering assistance. • R4 is confusing. Relay and equipment failures are not operations; they are operating events. Also, what is meant by the phrase "unless conditions do not permit such coordination"? • R5 is confusing and appears to duplicate R8. Delete R8 and reword R5 as follows: "Each Transmission Operator shall operate or direct others to operate within IROL Tv for each identified Interconnection Reliability Operating Limit (IROL)." • R6 should include identified IROLs in the communication to the RC. Reword R6 as follows: "Each Transmission Operator shall inform its Reliability Coordinator of all identified IROLs and those System Operating Limits (SOLs) which support its local area reliability." • Revise Measures and VSLs to reflect these changes to TOP-001-2
No
• R1 , M1 and Data Retention could be interpreted to require that daily assessments (which could include a dated Power Flow) will have to be kept for 6 months. This could take up a lot of space. • R2 as worded gives the impression that an IROL will be identified during a daily assessment respecting an SOL per R1. First, if you respect the SOL there will be no IROL. Second, simple day-ahead studies with an online Power Flow looking for contingencies might not identify an IROL. It might, but you would probably need to examine some multiple contingencies before something would cascade. R2 could be revised to read that each TOP shall plan to preclude operating in excess of any identified IROL's during the day-ahead assessment per R1. Also, maybe this requirement should be an RC requirement.
No
• The data specification in R1 is broad and could force a company to name every breaker, voltage point, MW point, etc. on their system. Perhaps an ICCP document or something similar could be used, but it's not clear as the requirement is currently written. • Also, this standard goes into a lot of detail in R1 through R4. This standard could be simply one requirement, R5.
Yes
Yes
The BA is involved in generation dispatch, which directly affects transmission flows.
No
We believe that more clarity is needed on the requirements in these standards before going to ballot.
Individual
Alice Murdock
Xcel Energy
No
R1- There is not an associated definition for the term Reliability Directive (nor is there one in the documents associated with Project 2006-06). The term "directive" is the subject of much debate as evidenced by the recent attempt at clarification by the NERC advisory on communications. This term needs to be defined and an opportunity for stakeholder comment, prior to moving this standard to ballot. R1- We feel that GOP should be removed from this requirement. The TOP should coordinate with any entity it necessary. Alternatively, it could be reworded to read: "The TOP shall coordinate operations with the GOP…". R2- Should be redrafted to read: "Each Transmission Operator shall inform its Reliability Coordinator and other impacted Transmission Operators of actual or anticipated Emergency conditions." Alternatively, this requirement could be abbreviated to have the TOP notify the RC, as the sharing of that condition by the RC to other impacted entities is covered by the proposed project 2006-06, IRO-001-2 R4: "Each Reliability Coordinator that identifies an expected or actual threat with Adverse Reliability Impacts, within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area." R3- Though addressed in the previous draft version, we continue to disagree with retaining this requirement. Determining if the other entity has implemented a comparable emergency procedure places the burden upon the entity providing assistance to verify completion of internal processes by the requesting entity. This is not reasonable or practical in an emergency situation, and requires the operator to make a subjective decision. Additionally, assuming the requesting entity is compliant with the NERC standards (e.g. EOP-002), there is no reason for the assisting entity to confirm that the deficient entity has properly implemented their comparable procedure. R4- The term 'reliability

impact' is vague. In reality, every change on the system has a reliability impact, whether it be positive or negative. We recommend instead using the phrase “adverse reliability impact”. To what degree must operations be coordinated? The proposed requirement indicates that changes in generation and Load must be coordinated. Does this mean changes in dispatch levels of every generator must be coordinated? How are changes in Load coordinated and what would constitute a significant change worthy of coordination? We recommend striking the last sentence that indicates examples. R5- This implies that the “Interconnection” will specify the IROL Tv. The NERC Glossary defines this at <= 30 minutes. Are there IROL Tvs <= 30 minutes? If not, why not just eliminate the hassle of trying to define and keep up with the IROL Tv and just state < 30 minutes in this requirement (and remove the IROL Tv definition)? R8- The phrase “…”within the IROL's Tv” should be deleted. The TOP should be directing others to act regardless of whether or not the elapsed time is within or exceeded the IROL Tv. 1.4. Data Retention The data retention section implies that compliance is to the Measure as well as the Requirement. We believe that compliance is measured to the Requirement only.
Yes
R1- Is there a need to specify IROLs as well?
No
R5- We are concerned that this may be liberally applied to require entities to provide data to other entities with no clear reliability need. We feel this requirement could place extreme and unnecessary burden on entities to provide data in a specified format and time interval.
Yes
No
No
We feel several modifications are needed before this is ready to ballot, as detailed in our previous responses. Also, the SDT indicates that changes in this project are dependent upon changes in Project 2006-06. Final drafts of those standards are not complete and it is not clear from a mapping perspective as to how some of the requirements originally in TOP are now covered under those standards.
Individual
Martin Bauer
US Bureau of Reclamation
No
The proposed addition of the term 'by the Transmission Operator" makes the Transmission Operator the reliability entity the exclusive source for determining when operations are expected to have a known or expected reliability impact on other reliability entities. This would eliminate the Generator Operator's ability to determine which operations can have an impact on other reliability entities such as Transmision Operators. The response from the SDT clearly indicated that "further the SDT recognizes that the scope and number of individual agreements, which may be needed to ensure that all operations are fully coordinated for all operations known or expected to have a reliability impact upon other Reliability Entities is highly likely to vary greatly from region to region or organizational arrangement to organizational arrangement.” If the Transmission Operator is to be the exlusive source for the determination of those operations have or are expected to have a reliability impact on other reliability entities, then a separate requirement and measure is needed to ensure that such a determination is properly conveyed to the Generator Operator. Prior to this addition, the Generator Operator was able to make the operational impact assessment. The SDT should either create a new requirement for the TOP to provide to the Generator Operators the operations that have or are expected to have impacts on reliability entities or alter the language that the reliability entities determine when their respective operations impact other realiability entities.
Yes
No
The modification of the language related to data specifications creates a potential for compliance

violation for the reliaibility entities other than the Transmission Operator. The specifications for data " necessary for Real-time monitoring and reliability assessments" needs to be more expicit. The language allows it to be below the BES voltage threshold. This is coupled with the requirement that no outstanding requests for rata from the transmission operator are unfilled. This double negative is easier to restate that all data requests from the transmission operator must be filled. This is very open ended. Should the data request is unreasonable, the other reliability entities would be non-compliant. The data specification need to be subject to review and approval by the Reliability Coordinator in the case of conflict brought by the reliabilty entity. The requirement, in case of conflict, would not be invoked until the data specifications are approved. This opportunity for appeal of the specifications ensures transmission operators apply technical reasoning in developing the specifications.
Yes
No
The term "Reliability Directive is not a defined term. The question is poorly worded since the TOP-001-2 R1 specifically reserves the reliability directive to Tranmission Operator for this standard. The Balancing Authority does not issue directives. It works within its capacity and emergency plan to aleviate imbalances. After implementing all of its remedies the Balancing authority works through the reliability coordinator. The Reliability Coordinator may declare an emergency and take specific actions. See the refercences below: EOP 002 - R2. Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system. R5. .... The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities. R6 If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: R6.1. Loading all available generating capacity. R6.2. Deploying all available operating reserve. R6.3. Interrupting interruptible load and exports. R6.4. Requesting emergency assistance from other Balancing Authorities. R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads. R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: R7.1. Manually shed firm load without delay to return its ACE to zero; and R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
No
The two outstanding issues related to the new language proposed by the SDT need to be resolved first. TOP 001 needs to be modified to either recognize that the GOP can determine which operations can impact other reliability entities or insert a new requirement that the TOP must develop and provide to the GOP the operations that may impact other reliability entities. TOP 003 needs to be modified to either place specific limitations on the data specifications developed by the TOP or that the Reliability Coordinator must approve data specification developed by the TOP when they are disputed by the reliability entity which must satisfy the obligations such data specifications impose on them.
Individual
Jason Shaver
American Transmission Organization
No
No requirement to define IROL TV. R6 is already covered in the MOD standards.
Yes

Yes
Yes
No
Because the team is use the term Reliability Directive our answer may depend on what how this term is finally defined. We believe that the term needs to be defined and approved by skateholders prior to this standard being posted for balloting.
No
Changes needed to remove R6 from draft TOP-001-2 and to include a requirement to establish TV for all IROL's.
Group
Platte River Power Authority Operations Group
Deb Schaneman
Yes
In R1 Reliability Directive is capitalized as a defined term but isn't in the NERC Glossary of Terms or Definitions or the Terms Used in Standard section of version 2 of the standard. Where is this term defined?
No
Is "an assessment" consistent with the interpretation of TOP-002-2 R11 by Orlando Utilities Commission or are you requiring a real-time contingency analysis tool? We believe there should be no requirements for the TOP to have a real-time contingency analysis tool if the BA and RC have the tool and model the TOP's system.
No
it isn't clear in R1 and R5 what is required for "Real-time...reliability assessments." Is a Real-time...reliability assessment" consistent with the interpretation of TOP-002-2 R11 by Orlando Utilities Commission or are you requiring a real-time contingency analysis tool? We believe there should be no requirement for the TOP to have a real-time contingency analysis tool if the BA and RC have the tool and model the TOP's system.
Yes
No
The Transmission Operator issues the "Transmission" reliability directive and the Balancing Authority issues directives to balance the generation to load.
No
Terms need to be defined and clarificaiton needs to be added.
Individual
Dan Rochester
Independent Electricity System Operator
No
(1) In R1, reliability directive is capitalized in indicating (or implying) it is a defined term. But this term has not yet been defined despite our understanding that there are currently three SDTs that are reviewing and/or attempting to define this term and the term (Directive). We suggest to make this term lower case until it is defined. (2) R2: the revised wording seems a bit odd as the phrase "expected to be affected" could be interpreted to be describing the actual or anticipated Emergency conditions. We suggest R2 to be revised to: "Each Transmission Operator shall inform its Reliability Coordinator and known or expected to be affected Transmission Operators of actual Emergency and anticipated Emergency conditions" to enhance clarity. Alternatively, we propose inserting a comma after "expected to be affected". (3) R3: We suggestion to add a comma after "...comparable emergency procedures". (4) R5 to R8: The very issue that we brought up during the last 2 postings came under the spot light with the changes made at this posting. The SDT in response to industry

comments made changes to qualify the SOLs whose exceedances are to be reported (in R7) based on a list of SOLs identified in R6 (the SDT added this requirement for this reason). While we don't think such identification is necessary, and in fact may expose the system to unreliability since such a list would be selective and hence bound to miss some SOLs that affect reliability, we nevertheless are encouraged by the changes and the addition since it is a step in the right direction. In our view though, it did not go far enough. However, without an explicit requirement that the TOP shall operate within all SOLs (as in the case for IROL in R5) and to act or direct others to act to mitigate the magnitude and duration of exceeding all SOL within some time frame (as in the case for IROL in R8), the requirements to identify a list of SOLs (in R6) and informing its Reliability Coordinator of actions being taken to return the system to within limits when one of these SOLs has been exceeded (in R7), appear inconsistent. We therefore recommend that R5 be altered as follows: R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL Tv, and each other System Operating Limit (SOL) and its associated time period as determined by the TOP. Similar to their IROL counterparts, operating within all SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations, although for IROLs the interconnected system impact is readily obvious than for SOLs. The same principle holds true for day-ahead operational planning so that the needed control measures can be identified and made available in advance to prevent operating in excess of SOLs and to mitigate exceedances if and when they occur during day at hand and real-time operations. (5) As pointed out in our previous comments, we did not agree that VSLs should be determined based on the number of times a requirement was violated. While it is appropriate to determine the VSLs for R6 based on the number of SOLs that support local area reliability not reported to the RC since these numbers represent the extent of missing the total set, the same approach should not be applied to the determination of R7 since the progressive VSLs appear to make a difference between IROL and SOL (Note: the former has a Severe VSL for failing to notify one exceedance whereas for the latter the VSLs are graded based on the number of SOLs whose exceedances a TOP failed to notify its RC). Note that R7 requires that the TOP inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. The requirement does not make any distinction between IROL and SOL, and requires that there shall not be even a single incident that the TOP does not inform its RC of actions being taken to mitigate an IROL or SOL exceedance. Hence, missing even one SOL would violate the bulk of the intent of R7. We suggest the VSLs for Low, Moderate and High be removed, and revise the VSL for Severe to: The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limit when an IROL or SOL has been exceeded.
No
(1) We continue to disagree with the way R2 is worded. R1 requires a TOP to conduct next day analysis to assess if any of the SOLs will be exceeded. R2 requires that the TOP develop plans to preclude operating in excess of only the IROLs identified as a result of the assessment performed in R1. Given our stance on this issue and understanding that IROLs represent a subset of SOLs, we believe R2 should be changed to refer to SOLs. In our view, a TOP needs to conduct next day analysis to assess if any of the established limits will be exceeded, develop plans to preclude operating in excess of the IROLs and SOLs, and make resources and actions available for mitigating exceedances if and when they occur. Like operating within SOL sand IROLs, this is fundamental to reliable operation. We suggest R2 be revised to include all SOLs.
Yes
Yes
No
The BA's role is to balance load-generation-interchange and does not have any direct role in monitoring and operating system conditions within transmission-related limits.
No
We continue to strongly disagree with removing the requirements for a TOP to plan and make day ahead arrangement for operating with all SOLs, and during day at hand and real time operate the system within established SOLs (and IROLs) and mitigate SOL exceedances within a predetermined time period. These are the most critical tasks for the TOPs, and are fundamental to ensuring

reliability. We are unable to support these standards if the necessary requirements are not reinstated/revised (as suggested in Q1 to change R5 of TOP-001 and in Q2 to change R2 of TOP-002). Finally, we recommend changing "local" in R6 to "Transmission Operator" to avoid creating ambiguity regarding what is referred to in the requirement.
Group
Bonneville Power Administration
Denise Koehn
No
Comments: The term "Reliability Directive" needs to be added to the NERC Glossary of Terms (it was not in the April 2009 version).
No
Comments: Change R1 wording. "R1:The wording is still incorrect in our interpretation. The wording needs to be changed to state that an assessment of the next days planned study conditions SOL'S is still valid with the expected next day's conditions. The previous wording isn't realistic because many days the assessment could determine a contingency response would cause the in place SOL to be exceeded. Some contingencies require the SOL to be lowered to prepare for the next condition which would cause real-time system readjustment. And the next contingency and the next contingency …. Some days the assessment would say the SOL could be exceeded for HLH. The key to those SOL'S is that the SOL'S are set at a level where the worst contingency for that path would not cause the interconnection to go unstable, i.e. cascading outages.. Suggest clarifying what is meant by "their" in R3: "Each Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s)." Perhaps state "their role in the TOP's Plans".
No
Regarding M4 (last sentence): "The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled". This doesn't mention the "TIMEFRAME" response time to provide data after a request is made. (i.e. 30 days, 60 days or whatever the reasonable "TIMEFRAME" is to modify databases or communication channels.) The VSL should be adjusted accordingly. If an entity has just received a request and is being audited the next week before fulfilling the request that would be a SEVERE VSL, which seems inappropriate.
Yes
No
Transmission-related issues are the responsibility of the TOP not the BA.
No
Correct R1 to assess the SOL is proper, not that the SOL could be exceeded. Where does the seasonal planning operations coordination described in TOP-002-2 R3 go? Re: the MOD-001-1 proposal.
Group
NERC Standards Review Subcommitte
Carol Gerou
No
A. In R4, states that the TOP and GOP shall coordinate operations "known or expected" by the TOP that have a reliability impact on other reliability entities. Is the TOP used twice in this requirement the same TOP or neighboring TOPs? Please clarify. B. In R4, the GOP will not know of "known or expected" operations of the TOP. Please clarify. C. In R4, as stated the GOP is required to notify the TOP of "relay and equipment failure and changes to generation", does this include all relays and all equipment associated with a generator? D. In R4, the reference to the term "Load", a TOP and GOP don't have loads. Therefore, how can they be required to coordinate something they don't have? Or E. In R4, the reference to the term "operating conditions", the GOP may not know of a severe or changing "operating condition" that is taking place on the transmission system. F. In R2 and R4, "expected to be affected" would include known. Please strike known. G. Both R5 and R6 require the TOP to identify a sub-set of SOLs that may be larger than the IROL subset ahead of time and notify the RC of what actions it is taking to return the system to within operating limits when they are exceeded. Why is there not a requirement to also operate within those SOLs and return within the

SOL if exceeded? H. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? I. The measures for R5 and R8 need to be clear than they currently are that these are event driven requirements and only data is required if an “event” has occurred.
Yes
N/A
No
The term “Long term outages” in the first sub bullet is not clear, please clarify.
Yes
N/A
No
The MRO NSRS believes any directives that a BA may issue should be in the BAL standards. R1, states that a BA, DP, LSE, and GOP shall comply with a Reliability Directive issued by a TOP. Reliability Directive is not defined by NERC. A definition has not been proposed.
No
A. A Reliability Directive must be defined and there must be an opportunity to comment before balloting can begin. B. Our responses to the previous questions are additional reasons why this standard should not go to ballot and that this standard needs another comment period.
Group
Midwest ISO Standards Collaborators
Jason L Marshall
No
We largely agree with the requirements but have a few suggestions. In R2 and R4, “expected to be affected” would include known. Please strike known. R5 and R6 require the TOP to identify a sub-set of SOLs that may be larger than the IROL subset ahead of time and to notify the RC of what actions it is taking to return the system to within operating limits when they are exceeded. Why is there not a requirement to also operate within those SOLs and return within the SOL if exceeded? The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for R5 and R8 need to be clear that these are event driven requirements and only evidence is required if an “event” has occurred.
Yes
Yes
Yes
No
Balancing Authorities do not operate transmission. They would only issue requirements with regard to capacity and energy emergencies.
Yes

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Real-time Operations Standards — Project 2007-03

The Real-time Operations Standard Drafting Team thanks all commenters who submitted comments on the third draft of the standards for Real-Time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from August 25, 2009 through September 24, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 26 sets of comments, including comments from more than 80 different people from over 45 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Changes have been made to the project standards as indicated below due to industry comments and miscellaneous updates:

Minor wordsmithing was done to TOP-001-2, Requirement R1 to add 'identified' to Reliability Directive so that there can be no confusion – the listed functional entities are only responsible for 'identified' Reliability Directives.

Requirement R2 was added to TOP-001-2 to allow a responsible entity to inform the Transmission Operator is it is unable to perform a Reliability Directive.

TOP-001-2, Requirement R3 was altered to tie the cited Emergencies to those noted in the assessment of the Operational Planning Analysis. This ties down the 'known or expected' language that caused some entities concern.

The Generator Operator was removed from TOP-001-2, Requirement R5 based on comments received which indicated that the Generator Operator did not posses the knowledge to participate in the required actions. This requirement was also changed to use the defined terms "Adverse Reliability Impact" to clarify what 'reliability impact' was involved and "Transmission Operator Areas" to clarify the portion of the BES involved.

TOP-001-2, Requirement R6 was added. This requirement is currently TOP-003-0, Requirement R3. The SDT believed that this requirement was going to be handled by another SDT and had originally deleted it from Project 2007-03. However, that is no longer the case and it is being added back in at this time.

TOP-001-2, Requirement R7 has had clarifying language added to show that the System Operating Limits identified in Requirement R8 are part of this requirement.

Requirement R8 of TOP-001-2 has been altered to indicate that the System Operating Limits cited will have been identified in the Operational Planning Analysis required in TOP-002-3, Requirement R1.

TOP-001-2, Requirement R9 was added to accommodate the addition of System Operating Limits in Requirement R8 similar to what was done in Requirement R7 for IROLs.

TOP-001-2, Requirement R10 has had some minor wordsmithing changes for additional clarity.

TOP-001-2, Requirement R11 has been clarified to indicate the System Operating Limits identified in Requirement R8 must be included here as well.

Requirements R12 through R14 have been added to TOP-001-2 to address a FERC Order 693 directive on minimum capabilities for Transmission Operators. Originally this directive was going to be handled by Project 2009-02, Real-time Reliability Monitoring and Analysis Capabilities but that project is now on indefinite hold so the need to address the directive has returned to Project 2007-03.

The VSL's for Requirements R3, R5, R8, and R10 of TOP-001-2 have been adjusted to align with the most recent VSL guidelines.

TOP-002-3, Requirement R1 was altered to make use of a defined term 'Operational Planning Analysis' that clearly shows the intent of what is required. A rationale text box was added to describe the reasoning for this change. TOP-002-3, Requirement R2 has been clarified to show that the System Operating Limits discussed in TOP-001-2 are included here.

Data retention for TOP-002-3 has been modified to agree with the latest guidelines.

The VSL's for TOP-002-3, Requirement R3 have been adjusted to align with the latest guidelines.

TOP-003-2, Requirements R1 and R5 have been changed to align with the addition of 'Operational Planning Analysis' in TOP-002-3.

TOP-003-2, Requirement R3 has been clarified so that monitoring and status are both explicitly included.

Measure M5 of TOP-003-2 has been changed to more clearly state what evidence is required.

The VSL's for Requirements R2 and R3 of TOP-003-2 have been changed to align with the latest guidelines.

Due to the number of comments received requesting an additional posting, and the number of changes made to the revised standards, the SDT agrees that an additional posting is required, however the team also recommends that this posting take place in parallel with an initial ballot.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herbert Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Greg Mason	Dynegy Generation	NPCC	5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
17.	Bruce Metruck	New York Power Authority	NPCC	6
18.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
19.	Robert Pellegrini	The United Illuminating Company	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
22.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		SERC	5
2.	Mike Garton		NPCC	6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Gerald Beckerle, Vice Chair - SERC Operating Committee	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Neagle	AECI	SERC	1, 3, 5
2.	Gene Delk	SCE&G	SERC	1, 3, 5
3.	J. T. Wood	Southern	SERC	1, 3, 5
4.	Steve Fritz	ACES Power Marketing	SERC	6
5.	Alan Jones	Alcoa	SERC	1, 5
6.	Hugh Francis	Southern	SERC	1, 3, 5
7.	Bob Dalrymple	TVA	SERC	1, 3, 5, 9
8.	Chad Randall	E.ON.US	SERC	1, 3, 5
9.	George Carruba	EKPC	SERC	1, 3, 5
10.	Brad Young	E.ON.US	SERC	1, 3, 5
11.	Timmy LeJeune	Louisiana Generating	SERC	1, 3, 6
12.	John Troha	SERC Reliability Corp.	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Ben Li	IRC Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

1.	Anita LEE	AESO	WECC	2
2.	Lourdes ESTRADA-SALINERO	CAISO	WECC	2
3.	H. Steven MYERS	ERCOT	ERCOT	2
4.	Matt GOLDBERG	ISO-NE	NPCC	2
5.	Bill PHILLIPS	MISO	RFC	2
6.	Jim CASTLE	NYISO	NPCC	2
7.	Patrick BROWN	PJM	RFC	2
8.	Charles YEUNG	SPP	SPP	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FirstEnergy	RFC	
2.	Dave Folk	FirstEnergy	RFC	
3.	John Reed	FirstEnergy	RFC	
4.	John Martinez	FirstEnergy	RFC	
5.	Andy Hunter	FirstEnergy	RFC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Deb Schaneman	Platte River Power Authority Operations Group	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Baker	Platte River Power Authority	WECC	1, 3, 5
2.	John Collins	Platte River Power Authority	WECC	1, 3, 5
3.	John Powell	Platte River Power Authority	WECC	1, 3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Transmission Technical Operations	WECC	1
2.	Tim Loepker	Transmission Dispatch	WECC	1
3.	Rebecca Berdahl	Power Long Term Sales & Purchases	WECC	3

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Carol Gerou	NERC Standards Review Subcommittee										X

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	WPS Corporation	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
4.	Ken Goldsmith	Alliant Energy	MRO	4
5.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
6.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
7.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
8.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Jason L Marshall	Midwest ISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Thomas	Illinois Municipal Electric Agency	SERC	4
2.	Joe O'brien	NIPSCO	RFC	1
3.	Barb Kedrowski	We Energies	RFC	3, 4, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Individual	Michael Davis	WECC RC										X
11.	Individual	Hugh Francis	Southern Company	X		X		X					
12.	Individual	James A Maenner	James A Maenner								X		
13.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
14.	Individual	Ed Stein	self								X		
15.	Individual	Michael Ayotte	ITC Holdings	X									
16.	Individual	Mike Gentry	Salt River Project	X		X		X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
17.	Individual	Ed Davis	Entergy Services, Inc	X		X		X	X				
18.	Individual	Larry Watt	Lakeland Electric	X		X		X					
19.	Individual	Daniel Herring	The Detroit Edison Company			X	X	X					
20.	Individual	Howard Rulf	We Energies			X	X	X					
21.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
22.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
23.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
24.	Individual	Martin Bauer	US Bureau of Reclamation					X					
25.	Individual	Jason Shaver	American Transmission Organization	X									
26.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. **TOP-001-2: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.**

Summary Consideration: A number of comments were received requesting clarification of terminology or intent within the various requirements. The SDT has answered all of the comments and made a number of the requested changes as shown below. However, no changes were made as to content or context of the requirements.

Due to industry comments, the following changes were made to the standard:

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

R8. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.

M1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, , evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M3. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and all other Transmission Operators that it knew or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M5. Each Transmission Operator shall make available upon request, evidence that operations it coordinated its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5 unless conditions did not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

R8 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5%	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more

	the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**
R10 VSL	N/A	N/A	N/A	The Transmission Operator did inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL as identified in Requirement R8, has been exceeded.

Organization	Yes or No	Question 1 Comment
Independent Electricity System Operator	No	(1) In R1, reliability directive is capitalized in indicating (or implying) it is a defined term. But this term has not yet been defined despite our understanding that there are currently three SDTs that are reviewing and/or attempting to define this term and the term (Directive). We suggest to make this term lower case until it is defined. (2) R2: the revised wording seems a bit odd as the phrase “expected to be affected” could be interpreted to be describing the actual or anticipated Emergency conditions. We suggest R2 to be revised to: “Each Transmission Operator shall inform its Reliability Coordinator and known or expected to be affected Transmission Operators of actual Emergency and anticipated Emergency conditions” to enhance clarity. Alternatively, we propose inserting a comma after “expected to be affected”. (3) R3: We suggestion to add a comma after “comparable emergency procedures”. (4) R5 to R8: The very issue that we brought up during the last 2 postings came under the spot light with the changes made at this posting. The SDT in response to industry comments made changes to qualify the SOLs whose exceedances are to be reported (in R7) based on a list of SOLs identified in R6 (the SDT added this requirement for this reason). While we don’t think such identification is necessary, and in fact may expose the system to unreliability since such a list would be selective and hence bound to miss some SOLs that affect reliability, we nevertheless are encouraged by the changes and the addition since it is a step in the right

Organization	Yes or No	Question 1 Comment
		direction. In our view though, it did not go far enough. However, without an explicit requirement that the TOP shall operate within all SOLs (as in the case for IROL in R5) and to act or direct others to act to mitigate the magnitude and duration of exceeding all SOL within some time frame (as in the case for IROL in R8), the requirements to identify a list of SOLs (in R6) and informing its Reliability Coordinator of actions being taken to return the system to within limits when one of these SOLs has been exceeded (in R7), appear inconsistent. We therefore recommend that R5 be altered as follows:R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL Tv, and each other System Operating Limit (SOL) and its associated time period as determined by the TOP. Similar to their IROL counterparts, operating within all SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations, although for IROLs the interconnected system impact is readily obvious than for SOLs. The same principle holds true for day-ahead operational planning so that the needed control measures can be identified and made available in advance to prevent operating in excess of SOLs and to mitigate exceedances if and when they occur during day at hand and real-time operations. (5) As pointed out in our previous comments, we did not agree that VSLs should be determined based on the number of times a requirement was violated. While it is appropriate to determine the VSLs for R6 based on the number of SOLs that support local area reliability not reported to the RC since these numbers represent the extent of missing the total set, the same approach should not be applied to the determination of R7 since the progressive VSLs appear to make a difference between IROL and SOL (Note: the former has a Severe VSL for failing to notify one exceedance whereas for the latter the VSLs are graded based on the number of SOLs whose exceedances a TOP failed to notify its RC). Note that R7 requires that the TOP inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. The requirement does not make any distinction between IROL and SOL, and requires that there shall not be even a single incident that the TOP does not inform its RC of actions being taken to mitigate an IROL or SOL exceedance. Hence, missing even one SOL would violate the bulk of the intent of R7. We suggest the VSLs for Low, Moderate and High be removed, and revise the VSL for Severe to:The Transmission Operator did not make available evidence that it had informed itsReliability Coordinator of actions being taken to return the system to within limit when an IROL or SOL has been exceeded.
Northeast Power Coordinating Council	No	(1) In R1, reliability directive is capitalized in indicating (or implying) it is a defined term. But this term has not yet been defined despite our understanding that there are currently three SDTs that are reviewing and/or attempting to define this term and the term (Directive). We suggest to make this term lower case until it is defined. (2) R2: the revised wording seems a bit odd as the phrase “expected to be affected” could be interpreted to be describing the actual or anticipated Emergency conditions. We suggest R2 to be revised to: “Each Transmission Operator shall inform its Reliability Coordinator and known or expected to be affected Transmission Operators of actual Emergency and anticipated Emergency conditions” to enhance clarity.

Organization	Yes or No	Question 1 Comment
		Alternatively, we propose inserting a comma after “expected to be affected”. (3) R3: Add a comma after “comparable emergency procedures”. (4)Similar to their IROL counterparts, operating within all SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations. (5) As pointed out in our previous comments, we did not agree that VSLs should be determined based on the number of times a requirement was violated. While it is appropriate to determine the VSLs for R6 based on the number of SOLs that support local area reliability not reported to the RC since these numbers represent the extent of missing the total set, the same approach should not be applied to the determination of R7 since the progressive VSLs appear to make a difference between IROL and SOL(Note: the former has a Severe VSL for failing to notify one exceedance whereas for the latter the VSLs are graded based on the number of SOLs whose exceedances a TOP failed to notify its RC). Note that R7 requires that the TOP inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or SOL as identified in Requirement R6, has been exceeded. The requirement does not make any distinction between IROL and SOL, and requires that there shall not be even a single incident that the TOP does not inform its RC of actions being taken to mitigate an IROL or SOL exceedance. Hence, missing even one SOL would violate the bulk of the intent of R7. We suggest the VSLs for Low, Moderate and High be removed, and revise the VSL for Severe to:The Transmission Operator did not make available evidence that it had informed itsReliability Coordinator of actions being taken to return the system to within limit when an IROL or SOL has been exceeded.

Response: (1) Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.

> **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

(2) The SDT has revised Requirement R2 (now Requirement R3) based on your comments and the comments of others.

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

(3) The comma has been added as suggested. (Note – Requirement R3 is now Requirement R4.)

> **R4**. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

(4) The SDT agrees that operating within a certain subset of SOLs such as IROLs is fundamental to reliability. However, the SDT does not believe operating within all SOLs is necessary and actually reduces reliability by eliminating an operator’s operational flexibility such as reducing the life of a piece of equipment

Organization	Yes or No	Question 1 Comment
to avoid shedding firm end use Load. However, the SDT realizes that there may be a certain set of SOLs that are considered important by the Transmission Operator and that would be treated in a similar vein to IROLs. The new Requirement R9 addresses this concern. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. (5) The SDT has reviewed the various VSLs to assure that they follow the latest guidelines and has revised several of them accordingly. Examples are shown below.		

R8 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**
R10 VSL	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL as identified in Requirement R8, has been exceeded.

MRO NERC Standards Review Subcommittee	No	A. In R4, states that the TOP and GOP shall coordinate operations “known or expected” by the TOP that have a reliability impact on other reliability entities. Is the TOP used twice in this requirement the same TOP or neighboring TOPs? Please clarify. B. In R4, the GOP will not know of “known or expected” operations of the TOP. Please clarify. C. In R4, as stated the GOP is required to notify the TOP of “relay and equipment failure and changes to generation”, does this include all relays and all equipment associated with a generator? D. In R4, the reference to the term “Load”, a TOP and GOP don’t have loads. Therefore, how can they be

Organization	Yes or No	Question 1 Comment
		required to coordinate something they don't have? Or E. In R4, the reference to the term "operating conditions", the GOP may not know of a severe or changing "operating condition" that is taking place on the transmission system. F. In R2 and R4, "expected to be affected" would include known. Please strike known. G. Both R5 and R6 require the TOP to identify a sub-set of SOLs that may be larger than the IROL subset ahead of time and notify the RC of what actions it is taking to return the system to within operating limits when they are exceeded. Why is there not a requirement to also operate within those SOLs and return within the SOL if exceeded? H. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages?I. The measures for R5 and R8 need to be clear than they currently are that these are event driven requirements and only data is required if an "event" has occurred.

Response: (A) This is the same Transmission Operator.

(B) The SDT agrees that the Generator Operator will not know of operations on the BES. The requirement has been deleted.

(C) This would include all relays and equipment that could impact the Bulk Electric System. Requirement R4 (now Requirement R5) has been changed to provide greater clarity as to the intent of the requirement.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

(D) A Transmission Operator must be able to forecast and monitor the Load on its portion of the Bulk Electric System. They must be aware of significant changes that could cause changes to expected Load. No change made.

(E) The SDT agrees that the Generator Operator will not know of operations on the BES. The requirement has been deleted.

(F) The SDT disagrees and feels that both terms are needed but has added terminology to clarify the expectation. (Note – Requirement R4 is now Requirement R5.)

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

(G) By definition, IROLs could result in cascading outages, widespread outages, and blackouts. SOLs will not. Thus, the SDT believes that requiring the

Organization	Yes or No	Question 1 Comment
Transmission Operator to operate within all SOLs that are not IROLs would eliminate the Transmission Operator's operational flexibility. However, the SDT realizes that there may be a certain set of SOLs that are considered important by the Transmission Operator and that would be treated in a similar vein to IROLs. The new Requirement R9 addresses this concern. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. (H) The SDT has reviewed the VSLs for Requirement R8 and revised them based on the latest guidelines.		

R8 VSL	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	No	Comments: The term “Reliability Directive” needs to be added to the NERC Glossary of Terms (it was not in the April 2009 version).
Platte River Power Authority Operations Group	Yes	In R1 Reliability Directive is capitalized as a defined term but isn't in the NERC Glossary of Terms or Definitions or the Terms Used in Standard section of version 2 of the standard. Where is this term defined?
IRC Standards Review Committee	No	Requirement 1: Reliability Directive, as a defined term has been introduced and the definition has not been provided in this posting. If the intent is to use this as a defined term anticipating that it will be defined and approved soon under a different project, then we suggest these standards not be put up for balloting until the term is approved.
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry. **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>Ed Stein - self</td><td>No</td><td>I do agree with most every thing However I do not understand what is meant by the phrase "expected to affect" a TO. How does the TO experiencing the emergency know if his emergency affect every TO. Granted he should know of the main ones but can he be sure that a remote line is affected that has a 2-5% response factor.</td></tr>
<tr><td colspan="3">Response: The SDT has made a clarifying change to the requirement which should alleviate your concern.

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.</td></tr>
<tr><td>ITC Holdings</td><td>No</td><td>In R2, strike the words “known or”.

In R4, remove the added words “by the Transmission Operator” from the second sentence . The addition of this phrase implies that the Generator Operator does have the obligation to initiate the coordination of changes in generation with the transmission operator. The requirement is clearer without this phrase.

In R4, change the wording to “Such operations MAY include”? We believe the intent of the sentence was only to provide a list of examples.

R6 requires the TOP to identify a sub-set of SOLs that is larger than IROLS and “support its local area reliability”. It is unclear what criteria a TOP would use to identify this subset, which will lead to inconsistent implementation and confusion. The TOP should inform the RC of all SOLs and the actions being taken to address any SOL exceedance which can be accomplished via SCADA or other means of action and communication when necessary.

The measures for R5 and R8 need to be clear that these are event driven requirements and only evidence is required if an “event” has occurred.</td></tr>
<tr><td colspan="3">Response: The SDT feels that the term ‘known’ has a different connotation than ‘expected’ and therefore both are required. However, the SDT has made clarifying changes so that expectations are clear. .

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

The SDT agrees with the second suggestion for Requirement R4 (now Requirement R5) and has made that change. However, the SDT does not agree with the deletion of Transmission Operator that was suggested and has retained it in the requirement.

R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. Based on comments received during the first and second posting, the industry did not reach a consensus that all SOL exceedances should be reported. The majority (it was a small majority) of responders felt that some subset of SOL exceedances should be reported. They felt the subset should be greater than IROLs but less than all SOLs. The remaining respondents were split between only IROLs and all SOLs. This split was likely based on the differing characteristics of the BES in various areas. Thus, the SDT felt drafting the requirement as is represented a reasonable compromise because the Transmission Operators could report the appropriate amount of SOLs based on the characteristics of their portion of the BES. Few additional comments have been received on this issue during this posting, thus the SDT assumes the industry largely agrees this is a reasonable compromise. The SDT feels that the measures are clear as written and has not made a change.		
SERC OC Standards Review Group	No	Is Reliability Directive a defined term since it is capitalized in R1 and throughout the Standard, but not currently found in the NERC Glossary of Terms. R2 We suggest that “other transmission operators” should be changed to “adjacent transmission operators”. R3 What is specifically meant by the words, “emergency assistance”? For example, do the words as written require a utility to provide line crews to assist in storm restoration? We suggest that the language be tightened up to focus emergency assistance on those things that were intended by the language. R4 we suggest removing “and Generator Operator” and the term “by the Transmission Operator” from the first sentence. It appears that the original wording implies that the Generator Operator would have knowledge of conditions on the transmission system. We also suggest removing the last sentence listing some but not all items that may have operating impacts and in which communications is necessary, concerns the SERC OC Standards Review Group. R6 We suggest revising R6 to read: Each Transmission Operator shall inform its Reliability Coordinator of any System Operating Limits (SOLs) which, while not IROLs, will require mitigating actions if exceeded. The current word “all” seems to indicate that every SOL would be in this list. R8 Why is R8 needed ? it appears to be a duplication of R5 and the two could be combined. General comment on measures: Measures that are event driven need to be clear that evidence would only be required if an event occurred. That is, the entity should not have to prove a negative.
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry. **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		

Organization	Yes or No	Question 1 Comment
The SDT discussed and felt that it is possible that some Transmission Operators could affect one another even if they are not adjacent as a result of sharing ties. Thus, no change has been made. R3 – Emergency assistance is not a defined term and could be different from entity to entity. The SDT can't define this term and doesn't feel that it is necessary. Each Transmission Operator will respond according to its set policies and procedures as required by EOP-001-2. No change made. The SDT agrees that the Generator Operator will not know of operations on the BES. However, the Generator Operator may know that his unit is critical to reliability. If his unit is critical to reliability, the SDT expects the Generator Operator should notify the Transmission Operator of all known issues that could reasonably be expected to cause the unit to be at a greater likelihood to be forced out. In Requirement R4 (now requirement R5), the SDT has modified the listing to reflect that it is not all inclusive based on comments from other respondents. **R5**. Each Transmission Operator shall coordinate its respective operations known or expected to have a Burden on the portion of the BES of other reliability entities with those entities unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, Load, or operating conditions. The SDT has modified the wording of Requirement R6 (now Requirement R8) to provide greater clarity. **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.** Requirements R5 & R8 (now Requirements R7 & R10) are slightly different and thus serve slightly different reliability goals. Requirement R7 (now Requirement R8) requires the Transmission Operator to operate within an IROL. Requirement R10 (now Requirement R11), however, requires the Transmission Operator to mitigate an exceedance if one has occurred. For example: If an exceedance occurs and goes away on its own within T_v, there is no violation of Requirement R7. However, if that exceedance occurs and the Transmission Operator doesn't act to mitigate it within T_v then they are in violation of Requirement R10. No change made. The SDT feels that the measures are clear as written and has not made a change in this regard.		
American Electric Power	No	It's our understanding that a definition of the term for a Reliability Directive (RD) may be currently under development/review/approval. However, since RD is not currently found in the NERC glossary, we request that it be added to the definition section of this standard. For example, are base points issued by the market area of an RTO considered an RD? Is there a method to distinguish such base points as constituting an RD from those that are not RDs? The team correctly capitalizes "Transmission" and "Load" since they are terms included in the NERC dictionary and does not capitalize "generation" since it is not included. It would seem that adding the term to NERC glossary would be the best resolution, but, in the interim, it should be well defined within the context that it is being used in any requirement (refer to R4). We are concerned that R5 is a duplication of a requirement in FAC-009 and perhaps others as well. Correspondingly, M5 would also be duplicative. Again, it appears that R6 may be duplicative of FAC-014, R5.2. If not, the phrase "support its local area reliability" should be clarified.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>While we appreciate the team’s efforts to better distinguish IROLs from SOLs in R7., more work is necessary to better define the difference. (e.g., exceeding limits vs. n-1)</td></tr>
<tr><td colspan="3">Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.

Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

The SDT does not believe this is a duplication of the FAC-009 requirements. While many SOLs will be based on a facility rating, not all SOLs are based on facility ratings. Thus, the requirement is needed.

The SDT does not feel that this requirement duplicates FAC-014 as the requirement is specific to those SOLs that are in support of local reliability. The SDT has clarified Requirement R8 to make it clear how the SOLs are identified.

R8. Each Transmission Operator shall inform it’s Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis.

IROLs are a defined subset of SOLs. The SDT believes that the FAC-011-2 and FAC-014-2 standards provide a great amount of detail to distinguish IROLs from SOLs.</td></tr>
<tr><td>American Transmission Organization</td><td>No</td><td>No requirement to define IROL TV.

R6 is already covered in the MOD standards.</td></tr>
<tr><td colspan="3">Response: FAC-014-2, Requirement R5.1.2 requires the Reliability Coordinator to identify the IROL T_V. No change made.

The SDT does not believe that Requirement R6 (now Requirement R9) is covered in the MOD standards. The SDT feels that you may have meant FAC-014-2. The SDT does not feel that this requirement duplicates FAC-014 as the requirement is specific to those SOLs that are in support of local reliability. The SDT has clarified Requirement R8 to make it clear how the SOLs are identified.

R8. Each Transmission Operator shall inform it’s Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis.</td></tr>
<tr><td>Manitoba Hydro</td><td>No</td><td>R.4 - The changes suggested to R. 4 are too vague to result in effective coordination.

What is meant by “expected relay failures”? How is an expected relay failure assessed? What criteria is used to determine what we consider a risk of an expected relay failure - what conditions?

R.6 - is again too vague for making consistent operating decisions. What criteria is applied for identifying SOL’s that support “local area reliability”? What is a local area, how large is it, what reliability criteria is violated on the violation of an SOL</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		R.7 – SOL's identified in R6 are vague.

Response: The intent of Requirement R4 (now Requirement R5) was to require coordination. The SDT has made clarifying changes to the requirement.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. .

Relay failures were cited as an example of conditions that may require coordination. The wording was changed to state 'may' apply so if you have nothing that applies to this condition, you do not have to coordinate them. No change made for this comment but clarifying language was applied.

> **R5**. Each Transmission Operator shall coordinate its respective operations known or expected to have a Burden on the portion of the BES of other reliability entities with those entities unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, Load, or operating conditions.

The SDT has clarified Requirement R8 to make it clear how the SOLs are identified.

> **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.**

Organization	Yes or No	Question 1 Comment
Electric Market Policy	No	R1 - By capitalizing the term "Reliability Directive", the SDT introduced a discrepancy as this term does not currently exist in the NERC Glossary of Terms. We are opposed to approving revisions to existing or new standards when they are predicated upon references to other "draft" terms, standards, requirements, etc. R4 We have reviewed the various comments made concerning retention of GOP in this requirement, and philosophically agree but find it impossible to determine how GOP can coordinate" its respective operations known or expected by the Transmission Operator to have a reliability impact". without knowing what constitutes "expected to have a reliability impact". The GOP can only coordinate to the extent the TOP has provided predefined information that is required to be coordinated. This information should be included in the Interconnection Agreement or some other agreement that clearly spells out what the GOP is expected to communicate in order to coordinate. We would prefer inclusion of this requirement in TOP-003 as part of R4 (referencing R2 and R3) or we could support the requirement in TOP-001 if it referenced coordination of data required in TOP-003 @ R2 and R3. Also the statement"operating conditions" is sufficiently vague. The SDT needs to clarify what constitutes an operating condition?

Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the

Organization	Yes or No	Question 1 Comment
recipient is necessary to address an actual or expected Emergency. The SDT agrees and has deleted the requirement. The wording was changed to state 'may' apply so if you have nothing that applies to this condition, you do not have to coordinate them. **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.		
Xcel Energy	No	R1- There is not an associated definition for the term Reliability Directive (nor is there one in the documents associated with Project 2006-06). The term "directive" is the subject of much debate as evidenced by the recent attempt at clarification by the NERC advisory on communications. This term needs to be defined and an opportunity for stakeholder comment, prior to moving this standard to ballot. R1- We feel that GOP should be removed from this requirement. The TOP should coordinate with any entity it necessary. Alternatively, it could be reworded to read: "The TOP shall coordinate operations with the GOP". R2- Should be redrafted to read: "Each Transmission Operator shall inform its Reliability Coordinator and other impacted Transmission Operators of actual or anticipated Emergency conditions."Alternatively, this requirement could be abbreviated to have the TOP notify the RC, as the sharing of that condition by the RC to other impacted entities is covered by the proposed project 2006-06, IRO-001-2 R4: "Each Reliability Coordinator that identifies an expected or actual threat with Adverse Reliability Impacts, within its Reliability Coordinator Area shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area." R3- Though addressed in the previous draft version, we continue to disagree with retaining this requirement. Determining if the other entity has implemented a comparable emergency procedure places the burden upon the entity providing assistance to verify completion of internal processes by the requesting entity. This is not reasonable or practical in an emergency situation, and requires the operator to make a subjective decision. Additionally, assuming the requesting entity is compliant with the NERC standards (e.g. EOP-002), there is no reason for the assisting entity to confirm that the deficient entity has properly implemented their comparable procedure. R4- The term "reliability impact" is vague. In reality, every change on the system has a reliability impact, whether it be positive or negative. We recommend instead using the phrase "adverse reliability impact". To what degree must operations be coordinated? The proposed requirement indicates that changes in generation and Load must be coordinated. Does this mean changes in dispatch levels of every generator must be coordinated? How are changes in Load coordinated and what would constitute a significant change worthy of coordination? We recommend striking the last sentence that indicates examples. R5- This implies that the "Interconnection" will specify the IROL Tv. The NERC Glossary defines this at <= 30

Organization	Yes or No	Question 1 Comment
		minutes. Are there IROL Tvs <= 30 minutes? If not, why not just eliminate the hassle of trying to define and keep up with the IROL Tv and just state < 30 minutes in this requirement (and remove the IROL Tv definition)? R8- The phrase “within the IROL’s Tv” should be deleted. The TOP should be directing others to act regardless of whether or not the elapsed time is within or exceeded the IROL Tv. 1.4. Data RetentionThe data retention section implies that compliance is to the Measure as well as the Requirement. We believe that compliance is measured to the Requirement only.

Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry.

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

Your second comment regarding Requirement R1 does not appear to be consistent with the requirement. Your comment appears to assume that Requirement R1 is focused on coordination but rather the requirement is for the Generator Operator among others to follow the Transmission Operator’s Reliability Directives. No change made.

The SDT agrees that there is some confusion created by the wording of the requirement and has modified the requirement based on the comments of other respondents in an attempt to provide greater clarity. However, the SDT did not adopt the term ‘impacted’.

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

The SDT disagrees with your comment regarding Requirement R3 (now Requirement R4). Requirement R3 (now Requirement R4) provides the Transmission Operator the option of not providing emergency assistance if the requesting Transmission Operator has not implemented comparable procedures. It does not require the assisting Transmission Operator to verify that the requesting Transmission Operator has implemented comparable procedures. The assisting Transmission Operator could simply provide emergency assistance rather than verifying the requesting Transmission Operator has not implemented its procedures. While the SDT does not favor inclusion of the comparable procedures language, the respondents in previous postings overwhelmingly desired the inclusion. It does not cause a reliability gap so the SDT cannot identify a reason not to include it. No change made.

R4 – The SDT has changed Requirement R4 (now Requirement R5) to provide greater clarity based on your comment and that of others.

> **R5**. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

R5 – Earlier standards work determined that the previous definition of IROL was not satisfactory and that the T_v definition was needed to improve the meaning. The SDT does not see a need to remove the definition. Further, the removal of the definition would expand the scope of the SDT beyond the Transmission Operator standards and is not warranted.

Organization	Yes or No	Question 1 Comment
R8 (now Requirement R11) – The SDT agrees the Transmission Operator should be acting with expediency to resolve an IROL. The requirement does not allow the Transmission Operator to wait to resolve the IROL exceedance but rather recognizes that the Transmission Operator requires time to assess how to resolve the exceedance. Assessing is one form of acting and the language of the requirement is appropriate as it is written. No change made. Data retention – The language in the data retention section is standard verbiage that simply states that you must retain the data necessary to measure the compliance with the requirement. No change made.		
FirstEnergy	No	R3 This requirement requires "comparable emergency procedures" be implemented which is appropriate and consistent with the previous standards, but it lacks, and the previous standards lacked, the concept of mitigation. An entity should not be required to shed load for the sake of requiring a neighboring entity to shed load to mitigate the emergency condition. As currently written, in order for an entity to require its neighbor to shed load that will mitigate the emergency condition, the requesting entity is required to shed load first. We suggest this be revised to say, "comparable emergency procedures that mitigate (lessen or eliminate) the impact of the emergency." R6 This requirement is ambiguous. By definition a System Operating Limit is "The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: (a) Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)? Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)? Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)? System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)"As written, the TOP will be required to inform the RC of all equipment ratings that "support local area reliability." This could be interpreted as requiring an entity to report equipment ratings for facilities operated at 100 kV or less which we believe is not the intent of the SDT. These facilities certainly support local area reliability on some level but are not monitored by the RC and serve little or no value to the RC.FAC-014-2 requires the TOP in Req. R2 to "establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology." Therefore, it appears that TOP-001-2 Req. R6 may not be necessary. However, if the intent of FAC-014-2 Req. R2 is to establish SOLs from an Operations PLANNING horizon (not sure since FAC-014-2 does not include time horizons with the requirements), and the intent of TOP-001-2 Req. R6 is to inform the RC from a REAL-TIME operations horizon, then Req. R6 of TOP-001-2 should be consistent with FAC-014 and written as follows: "R6. Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs) which are consistent with its Reliability Coordinator's SOL methodology."
Response: R3 – The SDT has modified the requirement (now Requirement R4) in response to other commenters. **R4**. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or		

Organization	Yes or No	Question 1 Comment
statutory requirements. R6 – Based on comments from other respondents, the SDT has modified Requirement R5 to use "Burden" rather than reliability impact. The SDT believes this will lessen your concern that facilities below 100 kV are included. Further, the SDT believes this issue is largely an issue around the definition of BES. Standards apply only to the BES and facilities impactive to the BES. Defining the BES is beyond the scope of this SDT. The SDT believes that FAC-014-2, Requirement R2 covers the operating horizon as well. The intent of Requirement R9 is not to duplicate FAC-014-2, Requirement R2 but for the Transmission Operator to identify the subset of SOLs from FAC-014-2, Requirement R2 that impact local area reliability to the point that the Reliability Coordinator may need to become involved. Thus, the Transmission Operator would communicate to the Reliability Coordinator SOL exceedances for this subset of SOLs. The SDT has made a clarifying change to Requirement R6 (now Requirement R8). **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.**		
Duke Energy	No	The definition of "Reliability Directive" drafted by the Reliability Coordination SDT should also be commented on in this TOP effort. We are concerned that the definition is too broad and would encompass what we consider normal communications. A key point of the definition should be that each communication of a Reliability Directive is required to be identified as such to the receiving entity. R2 should say that the TOP shall inform its RC and direct interconnected TOPs. The phrase "known or expected to be affected" opens the TOP to non-compliance if they don't expect someone to be affected, and it turns out that they are affected. R3 strike the phrase "provided that the requesting entity has implemented its comparable emergency procedures". In this situation we should not be wasting time getting proof that the requester has implemented their procedures before rendering assistance. R4 is confusing. Relay and equipment failures are not operations; they are operating events. Also, what is meant by the phrase "unless conditions do not permit such coordination" R5 is confusing and appears to duplicate R8. Delete R8 and reword R5 as follows: "Each Transmission Operator shall operate or direct others to operate within IROL Tv for each identified Interconnection Reliability Operating Limit (IROL)." R6 should include identified IROLs in the communication to the RC. Reword R6 as follows: "Each Transmission Operator shall inform its Reliability Coordinator of all identified IROLs and those System Operating Limits (SOLs) which support its local area reliability." Revise Measures and VSLs to reflect these changes to TOP-001-2
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.		

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<tr><td colspan="3">
Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.
R2 – (now Requirement R3) The SDT disagrees that only directly interconnected Transmission Operators should be included. It is possible that a Transmission Operator could be adversely impacted by another Transmission Operator that is not directly interconnected. Furthermore, the SDT has made a clarifying change to the requirement wording.
R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.
R3 - While the SDT does not favor inclusion of the comparable procedures language, the respondents in previous postings overwhelmingly desired the inclusion. It does not cause a reliability gap so the SDT cannot identify a reason not to include it.
R4 – (now Requirement R5) Relay failures were cited as an example of conditions that may require coordination. The wording was changed to state ‘may’ apply so if you have nothing that applies to this condition, you do not have to coordinate them.
R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.
The phrase “unless conditions do not permit such coordination” was intended to cover any situation that may prevent coordination from occurring up front. One example that may prevent coordination would be the need to take emergency actions such as ordering a unit to re-dispatch to relieve an IROL.
Requirements R5 & R8 (now Requirements R8 & R11) are slightly different and thus serve slightly different reliability goals. Requirement R8 requires the Transmission Operator to operate within an IROL. Requirement R11, however, requires the Transmission Operator to mitigate an exceedance if one has occurred. For example: If an exceedance occurs and goes away on its own within T_v, there is no violation of Requirement R8. However, if that exceedance occurs and the Transmission Operator doesn’t act to mitigate it within T_v then they are in violation of Requirement R11. No change made.
R6 (now Requirement R9) – IROL exceedances would be covered under Requirement R3 as they would represent an emergency condition. No change made.
VSLs and Measures have been revised as necessary.
</td></tr>
<tr><td>Southern Company</td><td>No</td><td>
The measure for R2 does not carry forth the definition of which other TOP should be informed. R2 requires informing other TOPs that are expected to be affected. The measurement requires that contact was made with all TOPs that were affected. The list of TOPs that are expected to be affected before the fact may be different than the list of TOPs that actually were affected.Would suggest minor change in R2 from “Transmission Operators known or expected to be affected of actual Emergency and anticipated Emergency conditions” to “Transmission Operators known or expected to be affected of actual Emergency or anticipated Emergency conditions”
The second “each” in M1 and M4 should be deleted.
Would suggest modifying VSL for M5 to read in the same tense of the Measure. Specifically, instead of “The Transmission Operator did not operate within an identified” to “The Transmission Operator operated outside
</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		an identified”
Response: The SDT agrees that there is some confusion created by the wording of the requirement and has modified the requirement based on the comments by you and other respondents in an attempt to provide greater clarity. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. **M3**. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and all other Transmission Operators that it knew or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. The SDT agrees that the second each in M1 and M5 should be deleted and has modified the measures accordingly. **M1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, in accordance with Requirement R1, evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. **M5.** Each Transmission Operator shall make available upon request, evidence that operations it coordinated its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5 unless conditions did not permit such coordination. Such evidence could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. While the proposed modification to Measure M6 is one way to write the VSL, the SDT does not see an issue with the way the VSL is currently modified and has left it unchanged.		
US Bureau of Reclamation	No	The proposed addition of the term 'by the Transmission Operator" makes the Transmission Operator the reliability entity the exclusive source for determining when operations are expected to have a known or expected reliability impact on other reliability entities. This would eliminate the Generator Operator's ability to determine which operations can have an impact on other reliability entities such as Transmision Operators.The response from the SDT clearly indicated that "further the SDT recognizes that the scope and number of individual agreements, which may be needed to ensure that all operations are fully coordinated for all operations known or expected to have a reliability impact upon other Reliability Entities is highly likely to vary greatly from region to region or organizational arrangement to organizational arrangement. If the Transmission Operator is to be the exlusive source for the determination of those operations have or are expected to have a reliability impact on other reliability entities, then a separate requirement and measure is needed to ensure that such a determination is properly conveyed to the Generator Operator. Prior to this addition, the Generator Operator was able to make the operational impact assessment. The SDT should

<table>
<tr><th>Organization</th><th>Yes or No</th><th colspan="5">Question 1 Comment</th></tr>
<tr><td></td><td></td><td colspan="5">either create a new requirement for the TOP to provide to the Generator Operators the operations that have or are expected to have impacts on reliability entities or alter the language that the reliability entities determine when their respective operations impact other realiability entities.</td></tr>
<tr><td colspan="7">Response: The SDT agrees that the Generator Operator will not know of operations on the BES and has deleted the requirement.</td></tr>
<tr><td>Midwest ISO Standards Collaborators</td><td>No</td><td colspan="5">We largely agree with the requirements but have a few suggestions.In R2 and R4, “expected to be affected” would include known. Please strike known.

R5 and R6 require the TOP to identify a sub-set of SOLs that may be larger than the IROL subset ahead of time and to notify the RC of what actions it is taking to return the system to within operating limits when they are exceeded. Why is there not a requirement to also operate within those SOLs and return within the SOL if exceeded?

The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages?

The measures for R5 and R8 need to be clear that these are event driven requirements and only evidence is required if an “event” has occurred.</td></tr>
<tr><td colspan="7">Response: The SDT feels that the term ‘known’ has a different connotation than ‘expected’ and therefore both are required. No change made.

The SDT determined that the Reliability Coordinator should be notified when the SOLs in Requirements R5 and R6 (now Requirements R8 & R9) are exceeded so that the assessor can be situationally aware and assess the need for additional action. At the same time, the SDT did not want to limit the operational flexibility of a Transmission Operator to temporarily exceed an SOL by a slight amount to avoid having to take drastic actions such as shedding load unnecessarily. No change made.

The SDT has reviewed all of the VSLs based on the latest guidelines and made changes accordingly. The R10 VSL is an example of such changes.</td></tr>
<tr><td>R10 VSL</td><td colspan="2">N/A</td><td>N/A</td><td>N/A</td><td colspan="2">The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL has been exceeded</td></tr>
<tr><td colspan="7">The SDT feels that the measures are clear as written and has not made a change.</td></tr>
<tr><td>WECC RC</td><td>No</td><td colspan="5">What is definition for when an SOL supports or does not support Local Area Reliabilty?</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		Is this for 100kV and above? What are the timing requirements for returning elements to a level below their SOL?
Response: The SDT has changed Requirement R8 to clarify this issue. **R8**. Each Transmission Operator shall inform it's Reliability Coordinator of all SOLs which, while not IROL, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.** The Reliability Standards are for the BES which is 100 kV and above unless specific exceptions are noted in the Applicability Section. Timing requirements would be based on the specific SOL characteristic such as if it is based on a facility thermal rating.		
James A Maenner	Yes	
Lakeland Electric	Yes	
Salt River Project	Yes	
The Detroit Edison Company	Yes	
Response: Thank you for your response.		

2. TOP-002-3: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: Industry comments centered on requests for clarification from the SDT. The SDT has responded to these comments and made changes as noted below.

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.

R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.

Data retention - Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling 90 day period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Organization	Yes or No	Question 2 Comment
Independent Electricity System Operator	No	(1) We continue to disagree with the way R2 is worded. R1 requires a TOP to conduct next day analysis to assess if any of the SOLs will be exceeded. R2 requires that the TOP develop plans to preclude operating in excess of only the IROLs identified as a result of the assessment performed in R1. Given our stance on this issue and understanding that IROLs represent a subset of SOLs, we believe R2 should be changed to refer to SOLs. In our view, a TOP needs to conduct next day analysis to assess if any of the established limits will be exceeded, develop plans to preclude operating in excess of the IROLs and SOLs, and make resources and actions available for mitigating exceedances if and when they occur. Like operating within SOL sand IROLs, this is fundamental to reliable operation. We suggest R2 be revised to include all SOLs.
Response: In response to your comment and those of others, the SDT has made a change to Requirement R2 to include certain, qualified SOLs that have been identified as needed for local are reliability. **R2**. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Northeast Power Coordinating Council	No	(1) We continue to disagree with the way R2 is worded. R1 requires a TOP to conduct next day analysis to assess if any of the SOLs will be exceeded. R2 requires that the TOP develop plans to preclude operating in excess of only the IROLs identified as a result of the assessment performed in R1. Given our stance on this issue and understanding that IROLs represent a subset of SOLs, we believe R2 should be changed to SOL. In our view, a TOP needs to conduct next day analysis to assess if any of the established limits will be exceeded, develop plans to preclude operating in excess of the IROLs and SOLs, and make resources and actions available for mitigating exceedances if and when they occur. Like operating within SOLs and

Organization	Yes or No	Question 2 Comment
		IROLs, this is fundamental to reliable operation. We suggest R2 be revised to include all SOLs. (2) Remove "single" from R1.
Response: (1) In response to your comment and those of others, the SDT has made a change to Requirement R2 to include certain, qualified SOLs that have been identified as needed for local are reliability. **R2**. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. (2) The SDT disagrees with removing single from Requirement R1. By not including the word single, some may interpret this requirement to operate within all multiple Contingencies which is contrary to how the industry operates and what is necessary for reliability. However, the SDT has made a clarifying change to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		
Bonneville Power Administration	No	Comments: Change R1 wording. "R1:The wording is still incorrect in our interpretation. The wording needs to be changed to state that an assessment of the next days planned study conditions SOL'S is still valid with the expected next day's conditions. The previous wording isn't realistic because many days the assessment could determine a contingency response would cause the in place SOL to be exceeded. Some contingencies require the SOL to be lowered to prepare for the next condition which would cause real-time system readjustment. And the next contingency and the next contingency ?. Some days the assessment would say the SOL could be exceeded for HLH. The key to those SOL'S is that the SOL'S are set at a level where the worst contingency for that path would not cause the interconnection to go unstable, i.e. cascading outages.. Suggest clarifying what is meant by "their" in R3:"Each Transmission Operator shall notify all reliability entities identified in theplan(s) cited in Requirement R2 as to their role in the plan(s)." Perhaps state "their role in the TOP's Plans".
Response: The SDT believes Requirement R1 as drafted aligns with the interpretation for TOP-002-2a, Requirement R11. However, the SDT has made clarifying changes to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. 'Their' refers to the antecedent all reliability entities. The SDT finds no additional clarity from the proposed wording change. No change made.		
Platte River Power Authority Operations Group	No	Is "an assessment" consistent with the interpretation of TOP-002-2 R11 by Orlando Utilities Commission or are you requiring a real-time contingency analysis tool?We believe there should be no requirements for the TOP to have a real-time contingency analysis tool if the BA and RC have the tool and model the TOP's system.

Organization	Yes or No	Question 2 Comment
Response: The SDT has made clarifying changes to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		
Duke Energy	No	R1 , M1 and Data Retention could be interpreted to require that daily assessments (which could include a dated Power Flow) will have to be kept for 6 months. This could take up a lot of space. R2 as worded gives the impression that an IROL will be identified during a daily assessment respecting an SOL per R1. First, if you respect the SOL there will be no IROL. Second, simple day-ahead studies with an online Power Flow looking for contingencies might not identify an IROL. It might, but you would probably need to examine some multiple contingencies before something would cascade. R2 could be revised to read that each TOP shall plan to preclude operating in excess of any identified IROL's during the day-ahead assessment per R1. Also, maybe this requirement should be an RC requirement.
Response: The SDT agrees with your concern and has changed the data retention to 90 days. **Data retention** - Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling 90 day period unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. R2. Requirement R2 requires an entity to compare SOLs/IROLs to flows and to identify any new SOLs/IROLs as needed. The SDT does not see that any additional clarity would be gained by the change of wording suggested for Requirement R2. No change made.		
WECC RC	No	R2 should include SOLs. In R3 the plan should be shared with the RC.
Response: The SDT believes SOL are local in nature and as such do not require a plan. When correctly identified, operating outside or exceeding a SOL will only harm the entity exceeding the SOL, not the Interconnection. R3. The Reliability Coordinator is a functional entity and is thus covered by the existing wording. No change made.		
IRC Standards Review Committee	No	Requirement #1: It is not clear why we introduce 'single' Contingency event since a TOP may be required to study multiple contingencies identified by its RC (See FAC-011-2, Requirement R3). A better term may be "Continegency events identified in FAC-011."
Response: The SDT disagrees with removing single from Requirement R1. By not including the word single, some may interpret this requirement to operate within all multiple Contingencies which is contrary to how the industry operates and what is necessary for reliability. However, the SDT has made clarifying change to the requirement. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		

Organization	Yes or No	Question 2 Comment
Salt River Project	No	
Response: Without specific comments, the SDT is unable to provide a response.		
Xcel Energy	Yes	R1- Is there a need to specify IROLs as well?
Response: IROLs are addressed in TOP-002-3, Requirement R2.		
Lakeland Electric	Yes	Requirement R-1 and Measure M-1 require modification for clarity. Replacing the undefined term “assessment” with the NERC defined term “Operational Planning Assessment” throughout the TOP-002-3 standard will help to clarify both line items. Using “Operational Planning Analysis” in measure M-1 clarifies that the power flow study does not have to be performed day-ahead (see the definition of Operational Planning Analysis). This is in-line with the recent interpretation issued by NERC discussed in the appendix of TOP-002-2a. Using “Operational Planning Analysis” in requirement R-1 ensures the planner understands that his or her assessment is meant to be more than just a determination of System Operating Limits. Requirement R-1 would also benefit from clarifying “single Contingency event.” Current day-ahead contingency analysis is limited to determining system performance during single transmission line, generator and transformer outages. However, using “single Contingency event” could include lightning struck towers with two or more transmission lines or even bus failures at which multiple transmission lines terminate. Unless it is the intent of the standard team to increase the scope of TOP-002 I recommend finishing requirement R-1 with “. . . involving transmission lines, transformers, and generators.”
Response: Operational Planning Assessment is not a currently defined term. The SDT believes that you meant ‘Operational Planning Analysis and agrees and has made the change. The SDT disagrees with removing single from Requirement R1. By not including the word single, some may interpret this requirement to operate within all multiple Contingencies which is contrary to how the industry operates and what is necessary for reliability. FAC-011-2 Requirement R3.3 already requires a Reliability Coordinator to determine SOLs from a list of multiple Contingencies that the Planning Coordinator identifies per FAC-014-2, Requirement R6 as having Stability limits. To remove the word single here would only cause confusion if additional multiple Contingencies over and above those used to identify SOLs in FAC-011-2, Requirement R3.3 are required to be tested. They are not required or needed for reliability. No change made in this regard. **R1**. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.		
Entergy Services, Inc	Yes	This standard seems to conflict with MOD-001, Requirement 7. This standard requires that: When calculating ATC or AFC the Transmission Service Provider shall use assumptions no more limiting than those used in the planning of operations for the corresponding time period studied, providing such planning of operations has been performed for that time period. When applying the requirements from TOP-002-3 along with the MOD-001 standard, it seems that all TSP’s will need to calculate ATC or AFC up to the calculated IROL for the time

Organization	Yes or No	Question 2 Comment
		period. When the two standards are looked at independently they are fine, when you look at both, there is some confusion on where NERC wants the TSP's to go.
Response: TOP-002-3 is not applicable to Transmission Service Providers and the SDT does not see any conflict. MOD-001, Requirement R7 requires AFC/ATC/TTC studies to use no more limiting assumptions than what is used in real-time studies, i.e., the Transmission Operator sets the limits and the Transmission Service Provider follows. No change made.		
American Electric Power	Yes	
American Transmission Organization	Yes	
Ed Stein - self	Yes	
Electric Market Policy	Yes	
FirstEnergy	Yes	
ITC Holdings	Yes	
James A Maenner	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
SERC OC Standards Review Group	Yes	
Southern Company	Yes	
The Detroit Edison Company	Yes	
US Bureau of Reclamation	Yes	

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Subcommittee	Yes	N/A
Response: Thank you for your response.		

3. TOP-003-1: Do you agree with the changes made to this standard? If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: Due to industry comments, the following clarifying changes were made:

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

Part 1.1, last bullet: Operating parameters for equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.

Part 1.3 A periodicity for providing data.

Part 1.4 The deadline by which the respondent is to provide the indicated data.

R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. . The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled.

Organization	Yes or No	Question 3 Comment
WECC RC	No	Is mutually agreeable a formal process? Should it be in writing? The RC should be involved because of the numerous formats it has to deal with.
Response: The SDT used the phrase 'mutually agreeable' because it did not feel it would be necessary to have one format that fits all, nor do it feel it would be feasible to do so. The SDT feels that this phrasing allows the entities involved the flexibility they need to make this happen and therefore does not believe that the process needs to be formal or in writing but recognizes that entities are not prevented from doing so. The requirement is clear that the specification must be 'documented.' The Reliability Coordinator is not required to be directly involved. This requirement is focused on the Transmission Operator and Balancing Authority receiving the date they need to perform their function to meet the NERC reliability requirements. Any data that the Transmission Operator or Balancing Authority needs to collect because the Reliability Coordinator requires the data from them is likely to be included in this list. Reliability Coordinator requirements are covered in the IRO family of standards.		
SERC OC Standards Review Group	No	R1 Does "specification for data" mean a complete listing of data points or a listing of types of data required for different types of facilities such as "generation, transmission, etc." Also, does this standard apply solely to internal requirements of a BA and its TOP? The concern is the multiple types of formats that may be required in order to exchange data with an expanded list of entities external to the BA or TOP.

Organization	Yes or No	Question 3 Comment
		M5 measurements should be modeled similar to the measurement in M4, in particular, that last sentence of M4. Is TOP-003-2 a new standard utilizing an existing number? If so, does the previous TOP-003-1, Planned Outage Coordination have to be retired? The migration from the current TOP-003-1 to the new TOP-003-2 seems like it could cause confusion. Would it be better to just retire TOP-003-1 and form a new standard number like TOP-011-1? R4 and R5: Should there be a time requirement for complying with a data request?

Response: The specification for data is intended to ensure the Transmission Operator and Balancing Authority have the data they need to complete their functional responsibilities. A complete listing of the data points or a listing of the types of data required would both seem to allow the Transmission Operator and Balancing Authority to specify the data they need to complete their function responsibilities.

M5 measures**:** The SDT agrees with your suggestion and has modified Measure M5 as shown below.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. . The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled.

TOP-003-1 will be retired as per the Implementation Plan filed for this project. The numbering scheme for standards is controlled by the NERC Standards Process Manager and is not in the scope of the SDT.

R4 and R5: The data specification required by Requirement R1 includes, per part 1.3, a timeframe and periodicity of the data. To clarify this, the SDT has broken this out into 2 distinct parts.

Part 1.3 A periodicity for providing data.

Part 1.4 The deadline by which the respondent is to provide the indicated data.

Organization	Yes or No	Question 3 Comment
Southern Company	No	R1 is written for the Operations Planning timeframe. As such, would suggest rewording “shall have a documented specification for data necessary for Real-time monitoring and reliability assessments” to “shall have a documented specification for data necessary for reliability assessments and Real-time monitoring”. Having “Real-time monitoring” mentioned first may convey the impression that “Real-time” also applies to the reliability assessments. Also, would suggest rewording “Equipment at voltage levels lower than” to “Outages of equipment at voltage levels lower than.”

Response: The SDT has made clarifying changes to the wording of the requirement.

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

Organization	Yes or No	Question 3 Comment
The SDT has clarified the wording for this part in response to your comment. **Part 1.1, last bullet**: Operating parameters for equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.		
Xcel Energy	No	R5- We are concerned that this may be liberally applied to require entities to provide data to other entities with no clear reliability need. We feel this requirement could place extreme and unnecessary burden on entities to provide data in a specified format and time interval.
Response: The SDT believes that the requirement is reasonable in that requests must fall within the parameters of the data specifications provided by each entity. No change made**.**		
Bonneville Power Administration	No	Regarding M4 (last sentence): "The evidence shall be that there are noTransmission Operators as identified in Requirement R2 or Balancing Authorities asidentified in Requirement R3 with outstanding requests for data to the subject entitythat have been unfilled".This doesn't mention the "TIMEFRAME" response time to provide data after a request is made. (i.e. 30 days, 60 days or whatever the reasonable "TIMEFRAME" is to modify databases or communication channels.) The VSL should be adjusted accordingly. If an entity has just received a request and is being audited the next week before fulfilling the request that would be a SEVERE VSL, which seems inappropriate.
Response: The SDT has clarified Parts 1.3 and 1.4 to address your concerns. **Part 1.3** A periodicity for providing data. **Part 1.4** The deadline by which the respondent is to provide the indicated data.		
Duke Energy	No	The data specification in R1 is broad and could force a company to name every breaker, voltage point, MW point, etc. on their system. Perhaps an ICCP document or something similar could be used, but it's not clear as the requirement is currently written. Also, this standard goes into a lot of detail in R1 through R4. This standard could be simply one requirement, R5.
Response: The specification for data is intended to ensure the Transmission Operator and Balancing Authority have the data they need to complete their functional responsibilities. A complete listing of the data points or a listing of the types of data required would both seem to allow the Transmission Operator and Balancing Authority to specify the data they need to complete their function responsibilities. The SDT believes that the requirements, as written, are correct and lend themselves more readily to measurement.		
US Bureau of Reclamation	No	The modification of the language related to data specifications creates a potential for compliance violation for the

Organization	Yes or No	Question 3 Comment
		reliaibility entities other than the Transmission Operator. The specifications for data " necessary for Real-time monitoring and reliability assessments" needs to be more expicit. The language allows it to be below the BES voltage threshold. This is coupled with the requirement that no outstanding requests for rata from the transmission operator are unfilled. This double negative is easier to restate that all data requests from the transmission operator must be filled. This is very open ended. Should the data request is unreasonable, the other reliability entities would be non-compliant. The data specification need to be subject to review and approval by the Reliability Coordinator in the case of conflict brought by the reliabilty entity. The requirement, in case of conflict, would not be invoked until the data specifications are approved. This opportunity for appeal of the specifications ensures transmission operators apply technical reasoning in developing the specifications.
Response: The SDT disagrees with your assessment. Part 1.3 has been changed and Part 1,4 added to address your concern. Part 1.2 requires a mutually agreeable format. Requirement R4 requires the entities receiving the data specification to provide it in a format that they agreed upon which includes the timeframe. **Part 1.3** A periodicity for providing data. **Part 1.4** The deadline by which the respondent is to provide the indicated data.		
MRO NERC Standards Review Subcommittee	No	The term "Long term outages" in the first sub bullet is not clear, please clarify.
American Electric Power	Yes	AEP would appreciate that the reference to "Long term outages" in R1.1.1. be specified in terms of the time elapsed.
Response: The Transmission Operator and Balancing Authority will have to define what long term outages are in their data specification. They could be different for various Transmission Operators and Balancing Authorities so no set time frame can be selected. No change made.		
Northeast Power Coordinating Council	Yes	Regarding R4, M4, it does not appear to be warranted that a Generator Owner, Generator Operator, Interchange Authority, or Load-Serving Entity provide evidence that there are no outstanding requests for data. As the originator of the request, the evidence that there are no outstanding requests for data should be provided by the Balancing Authority or Transmission Operator, as applicable.
Response: The SDT is addressing the need to show evidence without introducing the need to "prove a negative". If no outstanding request for data can be found, then compliance exists. If there has indeed been a request, but the entity has not provided the data, the requester will likely provide a complaint and a copy of the request. An attestation that all requests have been fulfilled may suffice. No change made.		
FirstEnergy	Yes	We agree with the changes to TOP-003-1. However, we feel that R3 should be re-written to be consistent with the wording in R2. We suggest a change as follows: "R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide

Organization	Yes or No	Question 3 Comment
		Facility status to the Balancing Authority."
Response: The SDT agrees with your suggestion and has changed the Requirement R3 wording to be consistent with the sequence contained in Requirement R2. **R3**. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.		
American Transmission Organization	Yes	
Ed Stein - self	Yes	
Electric Market Policy	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
ITC Holdings	Yes	
James A Maenner	Yes	
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
Salt River Project	Yes	
The Detroit Edison Company	Yes	
Response: Thank you for your response.		

4. TOP-004-3: Do you agree with the decision to move the lone remaining requirement of this standard to TOP-001-2? If not, please supply specific reasons why you do not agree with this move.

Summary Consideration: All respondents agreed with this change.

Organization	Yes or No	Question 4 Comment
American Electric Power	Yes	
American Transmission Organization	Yes	
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Ed Stein - self	Yes	
Electric Market Policy	Yes	
FirstEnergy	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
ITC Holdings	Yes	
James A Maenner	Yes	
Lakeland Electric	Yes	
Manitoba Hydro	Yes	
Midwest ISO Standards Collaborators	Yes	
Northeast Power Coordinating	Yes	

Organization	Yes or No	Question 4 Comment
Council		
Platte River Power Authority Operations Group	Yes	
Salt River Project	Yes	
SERC OC Standards Review Group	Yes	
Southern Company	Yes	
The Detroit Edison Company	Yes	
US Bureau of Reclamation	Yes	
WECC RC	Yes	
Xcel Energy	Yes	
NERC Standards Review Subcommittee	Yes	N/A
Response: Thank you for your response.		

5. TOP-001-2, Requirement R1: Do you believe that the Balancing Authority issues Reliability Directives directly for transmission-related limits and therefore should be in the TOP standards,(vote YES); or do you believe that the Balancing Authority in its role as a Balancing Authority issues Reliability Directives to balance load and generation and only indirectly affects transmission flows (recognizing that an entity that serves as both a Transmission Operator and a Balancing Authority would be covered under the Transmission Operator requirement) (Vote NO). Please be as specific as possible with your reply.

Summary Consideration: The overwhelming majority of respondents ‘voted’ No to this question which validates the position of the SDT. Thus, no changes were necessary.

Organization	Yes or No	Question 5 Comment
SERC OC Standards Review Group		We are unsure how to respond to this question as it pertains to TOP-001-2, R1.
Electric Market Policy	No	
Xcel Energy	No	
ITC Holdings	No	Balancing Authorities do not operate transmission. They would only issue requirements with regard to capacity and energy emergencies.
Midwest ISO Standards Collaborators	No	Balancing Authorities do not operate transmission. They would only issue requirements with regard to capacity and energy emergencies.
James A Maenner	No	BAs that neither own nor operate transmission should not issue reliability directives for transmission-related limits. Without the tools and knowledge of a Transmission Operator, the BA could isssue conflicting orders to the TOP's operating plans. Certainly, the BA should relay a TOP directive but not be the initiator.
Manitoba Hydro	No	The BA is responsible to operate its generation assets within the reliability constraints established by the Transmission Operator and Reliability Coordinator.
Independent Electricity System Operator	No	The BA’s role is to balance load-generation-interchange and does not have any direct role in monitoring and operating system conditions within transmission-related limits.
Northeast Power Coordinating Council	No	The BA’s role is to balance load-generation-interchange and does not have any direct role in monitoring and operating system conditions within transmission-related limits.

Organization	Yes or No	Question 5 Comment
IRC Standards Review Committee	No	The BA's role is to balance load-generation-interchange only; it does not have any direct role in monitoring and operating system conditions within transmission-related limits.
Platte River Power Authority Operations Group	No	The Transmission Operator issues the "Transmission" reliability directive and the Balancing Authority issues directives to balance the generation to load.
Bonneville Power Administration	No	Transmission-related issues are the responsibility of the TOP not the BA.
The Detroit Edison Company	No	We believe that the Balancing Authority in its role as a Balancing Authority issues Reliability Directives to balance load and generation and only indirectly affects transmission flows and should not be in the TOP standards.
WECC RC	No	In WECC, the RC deals mainly with the BAs. The BAs with their responsibility to maintain load and resources, ACE, and frequency places them in a position to direct and control all other activities on the interconnection. The RC expects the BAs to accomplish and direct actions to restore or mitigate contingencies in the interconnection.
Southern Company	No	TOP-001-2 does not mention any entity except for the Transmission Operator as issuing Reliability Directives.Yes, it is appropriate for the Balancing Authority to issue Reliability Directives that are related to his responsibilities (issues regarding balance load and generation), but there should be no confusion that the Reliability Coordinator has ultimate authority and thus could issues overriding Reliability Directives. The definition of a Balancing Authority in the NERC Glossary is, "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." This definition gives them no responsibility for transmission limits. However, the Balancing Authority does need to be able to give Reliability Directives in order to aid in the resolution of transmission-related limit problems.
We Energies	No	We Energies joined MISO's comments for this project. We have one additional comment for this question. The BA may need to issue Directives to Generator Operators or Distribution Providers in response to a TOP or RC need to resolve a transmission issue. Basically "pass-through" the Directive from the TOP or RC to the entity that will actually carry out the directed action.
Response: Thank you for your response.		
American Transmission Organization	No	Because the team is use the term Reliability Directive our answer may depend on what how this term is finally defined. We believe that the term needs to be defined and approved by skateholders prior to this standard being posted for balloting.

Organization	Yes or No	Question 5 Comment
US Bureau of Reclamation	No	The term "Reliability Directive is not a defined term. The question is poorly worded since the TOP-001-2 R1 specifically reserves the reliability directive to Tranmission Operator for this standard. The Balancing Authority does not issue directives. It works within its capacity and emergency plan to aleviate imbalances. After implementing all of its remedies the Balancing authority works through the reliability coordinator. The Reliability Coordinator may declare an emergency and take specific actions. See the refercences below:EOP 002 - R2. Each Balancing Authority shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.R5. . The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.R6 If the Balancing Authority cannot comply with the Control Performance andDisturbance Control Standards, then it shall immediately implement remedies to do so.These remedies include, but are not limited to:R6.1. Loading all available generating capacity.R6.2. Deploying all available operating reserve.R6.3. Interrupting interruptible load and exports.R6.4. Requesting emergency assistance from other Balancing Authorities.R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:R7.1. Manually shed firm load without delay to return its ACE to zero; andR7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.”R8. A Reliability Coordinator that has any Balancing Authority within its ReliabilityCoordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
NERC Standards Review Subcommittee	No	The MRO NSRS believes any directives that a BA may issue should be in the BAL standards. R1, states that a BA, DP, LSE, and GOP shall comply with a Reliability Directive issued by a TOP. Reliability Directive is not defined by NERC. A definition has not been proposed.
Response: Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn’t been approved by the industry. **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		
American Electric Power	Yes	Even in conditions where the BA is providing RDs to balance load and generation, the changes may still impact the BES. Under such circumstances, there remains a need for the BA to be aware of loadings on the BES.

Organization	Yes or No	Question 5 Comment
Duke Energy	Yes	The BA is involved in generation dispatch, which directly affects transmission flows.
Response: The Balancing Authority does not directly originate Directives to alleviate Transmission issues. They only respond to what they are told by the Reliability Coordinator or Transmission Operator. The majority of commenters agree with this position. No change made.		
FirstEnergy	Yes	The question as written is confusing based on the present wording of TOP-001-2 R1. Nevertheless, we believe that the Balancing Authority (BA) should be applicable in the TOP-001-2 standard and that their role as stated in R1 is correct. The BA receives direction from the TOP when redispatch solutions are needed to alleviate transmission-related limits (i.e. voltage, thermal, etc).
Ed Stein - self	Yes	
Lakeland Electric	Yes	
Response: Thank you for your response.		

6. Do you agree that with the changes in the 3rd posting that this project is ready to go to ballot? If not, please supply specific reasons why not.

Summary Consideration: No changes were made to requirements as a result of the comments received to this question. However, due to the number of comments received requesting an additional posting, and the number of changes made to the revised standards, the SDT agrees that an additional posting is required.

Organization	Yes or No	Question 6 Comment
Southern Company		Additional clarification per our previous comments is required. Re-posting may not be required.
Ed Stein - self	No	Due to my earlier response
Electric Market Policy	No	See comments above
WECC RC	No	See previous comments.
SERC OC Standards Review Group	No	See the above comments.Note: The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review Group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
ITC Holdings	No	The comments on TOP-001-2, particularly in regard to R6, need to be resolved before balloting.
Response: Please see the responses to previous comments.		
IRC Standards Review Committee	No	(1) The SRC is concerned that the absence of an explicit requirement for operating within SOLs may be problematic. Operating within SOLs is an important operating practice that will position the system to be stable within the acceptable reliability criteria included in the definition of SOLs and the requirements to be included in the methodology that is used to determine SOLs.The SRC recognizes that SOLs cover the full range from minor localized limits through Interconnection Operating Reliability Limits (IROLs), and that SOLs are defined to respect the facility and equipment ratings that are included in the determination of the values of SOLs. The suggested requirement R6 in TOP-001-2 for a TOP to identify SOLs, for which the TOP is to notify the RC when the SOLs are exceeded, is intended to address those SOLs that, while not meeting the definition of IROLs, may have potential impact that is important from a local viewpoint. Although these SOLs may not cause an impact equivalent to or greater than that in the definition of Adverse Reliability Impact, they deserve additional attention, including monitoring and notifications between TOPs and RCs. If the SDT holds the view that operating within the identified SOLs and correcting their exceedances are implicit and precursory to R7 and R8, then we would

Organization	Yes or No	Question 6 Comment
		suggest to make it explicit by revising R5, by saying, for example: R5. Each Transmission Operator shall operate within each identified Interconnection Reliability Operating Limit (IROL) and its associated IROL Tv, and each System Operating Limit (SOL) as identified in R6 and its associated time period as determined by the TOP. Similar to their IROL counterparts, operating within SOLs and mitigating their exceedances within some predetermined time period is fundamental to reliable operations, although for IROLs the interconnected system impact is readily obvious compared to the SOLs. The same principle holds true for day-ahead operational planning so that the needed control measures can be identified and made available in advance to prevent operating in excess of SOLs and to mitigate exceedances if and when they occur during day at hand and real-time operations. To this end, we suggest the SDT consider revising R2 of TOP-002-3 to: "Each Transmission Operator shall plan to preclude operating in excess of those System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) identified as a result of the assessment performed in Requirement R1." (2) Also there is concern that a definition for Reliability Directive has not been determined and agreed upon through the standards development process. Until such time that the definition of Reliability Directive can be developed and agreed to, the references to Reliability Directives or these standards should not go to ballot.
Response: The SDT agrees that operating within a certain subset of SOLs such as IROLs is fundamental to reliability and has made changes throughout TOP-001-2 and TOP-002-3 accordingly. (2) Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry. **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.		
NERC Standards Review Subcommittee	No	A. A Reliability Directive must be defined and there must be an opportunity to comment before balloting can begin. B. Our responses to the previous questions are additional reasons why this standard should not go to ballot and that this standard needs another comment period.
Response: A. Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated to a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry. **Reliability Directive -** A communication initiated by a Reliability Coordinator, Transmission Operator or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency. B. The SDT agrees that one more draft and posting is necessary.		

Organization	Yes or No	Question 6 Comment
American Electric Power	No	AEP believes that one more draft is needed to verify that key edits provided by stakeholders during this round are included before proceeding to ballot.
Response: The SDT agrees that one more posting is necessary..		
Manitoba Hydro	No	Changes are still required to TOP-001-2
Response: The SDT has made changes to TOP-001-2 and agrees that one more posting is necessary.		
American Transmission Organization	No	Changes needed to remove R6 from draft TOP-001-2 and to include a requirement to establish TV for all IROL's.
Response: Requirement R6 (now Requirement R8) was added in response to substantial industry comments received in the second posting and remains in the proposed standard. FAC-014-2, Requirement R5.1.2 requires the Reliability Coordinator to identify the IROL T_v. No change made.		
Bonneville Power Administration	No	Correct R1 to assess the SOL is proper, not that the SOL could be exceeded. Where does the seasonal planning operations coordination described in TOP-002-2 R3 go? Re: the MOD-001-1 proposal.
Response: The SDT does not understand the comment nor is it able to see a correspondence to any of the Requirement R1's. Without a definitive reference, the SDT is unable to respond to your comment. The new TOP-003-2, Requirement R1 addresses all time frames, including seasonal planning operations coordination.		
Platte River Power Authority Operations Group	No	Terms need to be defined and clarificaiton needs to be added.
Duke Energy	No	We believe that more clarity is needed on the requirements in these standards before going to ballot.
Response: The SDT has clarified requirements, defined terms and agrees that one more draft and posting is necessary.		
US Bureau of Reclamation	No	The two outstanding issues related to the new language proposed by the SDT need to be resolved first.TOP 001 needs to be modified to either recognize that the GOP can determine which operations can impact other reliability entities or insert a new requirement that the TOP must develop and provide to the GOP the operations that may impact other reliability entities.

Organization	Yes or No	Question 6 Comment
		TOP 003 needs to be modified to either place specific limitations on the data specifications developed by the TOP or that the Reliability Coordinator must approve data specification developed by the TOP when they are disputed by the reliability entity which must satisfy the obligations such data specifications impose on them.
Response: The SDT agrees that the Generator Operator will not know of operations on the BES and has deleted the requirement. The SDT has changes Part 1.3 and added Part 1.4 to address these concerns. Part 1.2 requires a mutually agreeable format. Requirement R4 requires the entities receiving the data specification to provide it in a format that they agreed upon which includes the timeframe.		
Independent Electricity System Operator	No	We continue to strongly disagree with removing the requirements for a TOP to plan and make day ahead arrangement for operating with all SOLs, and during day at hand and real time operate the system within established SOLs (and IROLs) and mitigate SOL exceedances within a predetermined time period. These are the most critical tasks for the TOPs, and are fundamental to ensuring reliability. We are unable to support these standards if the necessary requirements are not reinstated/revised (as suggested in Q1 to change R5 of TOP-001 and in Q2 to change R2 of TOP-002). Finally, we recommend changing “local” in R6 to “Transmission Operator” to avoid creating ambiguity regarding what is referred to in the requirement.
Response: The SDT has made numerous changes to TOP-001-2 and TOP-002-3 to include the concept of local reliability SOLs. In Requirement R6 (now Requirement R8) “local” was intended to clarify that these SOLs, while important, did not affect bulk power system reliability. The SDT continues to believe that the use of the word “local” conveys the intent better than the term “Transmission Operator” would.		
Northeast Power Coordinating Council	No	We continue to strongly disagree with removing the requirements for a TOP to plan and make day ahead arrangement for operating with all SOLs, and during day at hand and real time operate the system within established SOLs (and IROLs) and mitigate SOL exceedances within a predetermined time period. These are the most critical tasks for the TOPs, and are fundamental to ensuring reliability. We are unable to support these standards if the necessary requirements are not reinstated/revised (as suggested in Q1 to change R5 of TOP-001 and in Q2 to change R1 and R2 of TOP-002). R6 should be reworded to read "Each Transmission Operator shall inform its Reliability Coordinator of all System Operating Limits (SOLs)which, while not IROLs, support its Transmission Operator area reliability.
Response: The SDT has made numerous changes to TOP-001-2 and TOP-002-3 to include the concept of local reliability SOLs.		
Xcel Energy	No	We feel several modifications are needed before this is ready to ballot, as detailed in our previous responses. Also, the SDT indicates that changes in this project are dependent upon changes in Project 2006-06. Final drafts of those standards are not complete and it is not clear from a mapping perspective as to how some of the

Organization	Yes or No	Question 6 Comment
		requirements originally in TOP are now covered under those standards.
FirstEnergy	No	We feel that the current draft still has issues to be addressed before balloting begins (see our comments on Questions 1 through 5). Also, we provide the following additional comments:1. The mapping of all the requirements and standards associated with this project provided within the Implementation Plan during the first posting is a valuable tool for industry personnel in charge of tracking compliance. However, this mapping matrix now appears to be removed from the implementation plan. We feel that the team and/or NERC should provide a revised mapping document during the next posting of documents for this project so that industry can review it. Then it should be retained as a reference tool for industry when transitioning their compliance documentation from the current standards to the new standards. 2. The implementation plan currently states: "The assumption used by the SDT in establishing this Implementation Plan is that the project mentioned in the prerequisites: Project 2006-06, Reliability Coordination; has been approved prior to the implementation of this Project 2007-03, Real-Time Operations." It should be clear that the implementation clock for these Real-Time Operations standards starts only after "applicable regulatory approval" of the standards associated with Project 2006-06.
Response: The SDT agrees that one more posting is necessary. The mapping matrix, which clearly identifies the linkages to Project 2006-06, has undergone substantial revision and will be provided with the next posting. The current plan of the SDT for this project is to submit it for approval simultaneously with Project 2006-06, Reliability Coordination.		
James A Maenner	Yes	
Lakeland Electric	Yes	
Midwest ISO Standards Collaborators	Yes	
Salt River Project	Yes	
The Detroit Edison Company	Yes	
Response: Thank you for your response.		

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. The current draft is the fourth posting of the revised standards and represents one additional posting that was not anticipated. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	2Q10
2. Post for recirculation ballot.	TBD
3. Submit to BOT.	TBD

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated on a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency.

A. Introduction

1. **Title:** **Coordination of Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

   4.4. Distribution Providers

   4.5. Load-Serving Entities

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity informs its Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform a Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators unless conditions do not permit such coordination. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall coordinate planned outages of telemetering and control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v or an SOL identified in Requirement R8. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

Requirements R12, R13, and R14 are in response to FERC Order 693, paragraphs 1660 & 1661 dealing with minimum capabilities for the Transmission Operator.

R12. Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities within its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R13. Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Same-day Operations, Operations Planning]*

R14. Each Transmission Operator shall provide approval rights for planned maintenance of its monitoring and analysis capabilities to its System Operators. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

C. Measures

M1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with issued Reliability Directive(s) in accordance with Requirement R2.

M3. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and all other Transmission Operators that it knew or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. Each Transmission Operator shall make available upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M5. Each Transmission Operator shall make available upon request, evidence that operations it coordinated its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5 unless conditions did not permit such coordination. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M6. Each Transmission Operator, Balancing Authority, and Generator Operator shall make available upon request, evidence that planned outages of telemetering and control equipment and associated communication channels were coordinated among impacted reliability entities in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M8. Each Transmission Operator shall make available evidence that it has informed it's Reliability Coordinator of each SOLs which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration exceeding 30 minutes as specified in Requirement R9. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R9. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v or

SOL identified in Requirement R8 in accordance with Requirement R10 Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M12. Each Transmission Operator shall make available evidence that it can monitor, or has access to information about, conditions and Facilities within its Transmission Operator Area in accordance with Requirement R11. Such evidence could include Energy Management System description documents, computer printouts, or SCADA data collection system communications performance printouts.

M13. Each Transmission Operator shall make available evidence that it can monitor, or has access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area in accordance with Requirement R12. Such evidence could include Energy Management System description documents, computer printouts, or SCADA data collection system communications performance printouts.

M14. Each Transmission Operator shall make available evidence that it's System Operators have approval rights for planned maintenance of its monitoring and analysis capabilities in accordance with Requirement R13. Such evidence could include a documented procedure that shows that the Transmission Operator's System Operator has the authority to veto planned outages to monitoring and analysis capabilities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance for each applicable Requirement R1 through R6, R8, and R10 through R14 and Measure M1 through M6, M8, and M10 through M14 for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with a Reliability Directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not comply with a Reliability Directive issued by its Transmission Operator, and the respective entity did not inform the Transmission Operator of its inability to do so.
R3	The Transmission Operator did not inform one other affected Transmission Operator or 5% or less of the other Transmission Operators affected whichever is less of an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other affected Transmission Operators or more than 5% or less than or equal to 10% of the affected Transmission Operators whichever is less of an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other affected Transmission Operators or more than 10% or less than or equal to 15% of the affected Transmission Operators whichever is less of an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other affected Transmission Operators or more than 15% of the affected Transmission operators whichever is less of an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting entity had implemented its comparable emergency procedures, and such

	Lower	Moderate	High	Severe
				actions would not have violated safety, equipment, regulatory, or statutory requirements.
R5	The Transmission Operator did not coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with one affected reliability entity or 5% or less of the affected reliability entities whichever is less when conditions did permit such coordination.	The Transmission Operator did not coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with two affected reliability entities or more than 5% or less than or equal to 10% of the affected reliability entities whichever is less when conditions did permit such coordination.	The Transmission Operator did not coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with three affected reliability entities or more than 10% or less than or equal to 15% of the affected reliability entities whichever is less when conditions did permit such coordination.	The Transmission Operator did not coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with four or more affected reliability entities or more than 15% of the affected entities whichever is less when conditions did permit such coordination.
R6	The responsible entity did not coordinate its respective planned outages of telemetering and control equipment and associated communication channels with one affected reliability entity or 5% or less of the affected entities whichever is less.	The responsible entity did not coordinate its respective planned outages of telemetering and control equipment and associated communication channels with two affected reliability entities or more than 5% or less than or equal to 10% of the affected entities whichever is less.	The responsible entity did not coordinate its respective planned outages of telemetering and control equipment and associated communication channels with three affected reliability entities or more than 10% or less than or equal to 15% of the affected entities whichever is less.	The responsible entity did not coordinate its respective planned outages of telemetering and control equipment and associated communication channels with four or more affected reliability entities or more than 15% of the affected entities whichever is less.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**

	Lower	Moderate	High	Severe
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R9 for a continuous duration greater than 30 minutes.
R10	N/A	N/A	N/A	The Transmission Operator did notinform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v or SOL identified in Requirement R8.
R12	N/A	N/A	N/A	The Transmission Operator did not have monitoring capability, or access to information about, the conditions and Facilities within its Transmission Operator Area.
R13	N/A	N/A	N/A	The Transmission Operator did not monitor, or have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area.
R14	N/A	N/A	N/A	The Transmission Operator's System operator did not have approval rights for planned maintenance of its monitoring and analysis capabilities.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
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4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.

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1. Post for ballot.	2Q10
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3. Submit to BOT.	TBD

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated on a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency.

A. Introduction

1. **Title:** **Coordination of Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

   4.4. Distribution Providers

   4.5. Load-Serving Entities

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by ~~the~~ its Transmission Operator, unless the respective entity informs ~~the~~ its Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

~~R1.~~R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform a Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergenc~~y~~ies based on its assessment of its Operational Planning Analysis ~~and anticipated Emergency conditions~~. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

~~R2.~~R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

~~R3.~~R5. Each Transmission Operator ~~and Generator Operator~~ shall coordinate its ~~respective~~ operations known or expected ~~by the Transmission Operator~~ to ~~have~~result in ~~a reliability impact~~ an Adverse Reliability Impact on ~~the portion of the BES of~~ other ~~reliability entities~~Transmission Operator Areas with those ~~entities~~ Transmission Operators unless conditions do not permit such coordination. Such operations may include~~, but are not limited to,~~ relay or equipment failures and changes in generation, Transmission, or Load ~~or operating conditions~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall coordinate planned outages of telemetering and control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

~~R4.~~R7. Each Transmission Operator shall not operate ~~within~~outside ~~each~~any identified Interconnection Reliability Operating Limit (IROL) ~~and~~for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

~~R5.~~R8. Each Transmission Operator shall inform its Reliability Coordinator of all ~~System Operating Limits (~~SOLs~~)~~ which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

~~R9.~~R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions ~~being taken~~ to return the system to within limits when an IROL, or each SOL ~~as~~ identified in Requirement R~~6~~8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v or an SOL identified in Requirement R8. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

Requirements R12, R13, and R14 are in response to FERC Order 693, paragraphs 1660 & 1661 dealing with minimum capabilities for the Transmission Operator.

R12. Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities within its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

~~R12.~~R13. Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Same-day Operations, Operations Planning]*

R14. Each Transmission Operator shall provide approval rights for planned maintenance of its monitoring and analysis capabilities to its System Operators. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

C. Measures

M1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall ~~each~~ make available upon request, ~~in accordance with Requirement R1,~~ evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission

Operator of its inability to comply with issued Reliability Directive(s) in accordance with Requirement R2.

~~**M2.**~~**M3.** Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and ~~affected~~ all other Transmission Operators that it knew or expected to be affected of actual ~~Emergency~~ and anticipated Emergenc~~y~~ies ~~conditions~~ based on its assessment of its Operational Planning Analysis in accordance with Requirement R~~2~~3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

~~**M3.**~~**M4.** Each Transmission Operator shall make available upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R~~3~~4 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

~~**M4.**~~**M5.** Each Transmission Operator ~~and Generator Operator~~ shall ~~each~~ make available upon request, evidence that operations ~~were~~ it coordinated its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas with those Transmission Operators ~~among with impacted reliability entities~~ in accordance with Requirement R~~4~~5 unless ~~-~~conditions ~~do~~ did not permit such coordination. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M6. Each Transmission Operator, Balancing Authority, and Generator Operator shall make available upon request, evidence that planned outages of telemetering and control equipment and associated communication channels were coordinated among impacted reliability entities in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

~~**M5.**~~**M7.** Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) ~~and~~for a continuous duration exceeding its associated IROL T_v as specified in Requirement R~~58~~7. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion ~~outside of the identified IROL and applicable IROL T_v~~.

~~**M6.**~~**M8.** Each Transmission Operator shall make available evidence that it has informed ~~its~~it's Reliability Coordinator of ~~all~~ each SOLs which, while not an IROL~~s~~, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R~~6~~8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration exceeding 30 minutes as specified in Requirement R9. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

~~**M9.**~~**M10.** Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an

IROL, or ~~each~~an SOL ~~as~~ identified in Requirement R~~6~~8, has been exceeded in accordance with Requirement R~~7~~9. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

~~M10.~~M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v or SOL identified in Requirement R8 in accordance with Requirement R~~8~~10~~.~~ Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

~~M11.~~M12. Each Transmission Operator shall make available evidence that it can monitor, or has access to information about, conditions and Facilities within its Transmission Operator Area in accordance with Requirement R11. Such evidence could include Energy Management System description documents, computer printouts, or SCADA data collection system communications performance printouts.

M13. Each Transmission Operator shall make available evidence that it can monitor, or has access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area in accordance with Requirement R12. Such evidence could include Energy Management System description documents, computer printouts, or SCADA data collection system communications performance printouts.

M14. Each Transmission Operator shall make available evidence that it's System Operators have approval rights for planned maintenance of its monitoring and analysis capabilities in accordance with Requirement R13. Such evidence could include a documented procedure that ~~will~~ shows that the Transmission Operator's System Operator has the authority to veto planned outages to monitoring and analysis capabilities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~1.2.~~Regional Entity ~~**Compliance Monitoring and Reset Time Frame**~~

~~Not applicab~~

~~1.3.~~1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.4.~~1.3. Data Retention

Each Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance for each applicable Requirement R1 through R~~4~~6, R8, and R~~6~~10 through R~~8~~1~~0~~34 and Measure M1 through M~~4~~6, M8, and M~~6~~10 through M~~8~~14 for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v or SOL ~~as~~ identified in Requirement R8 as specified in Requirements R~~5~~7 and R9 and Measurements M~~5~~7 and M9.

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

~~1.5.~~1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with a Reliability Directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not comply with a Reliability Directive issued by its Transmission Operator, and the respective entity did not inform the Transmission Operator of its inability to do so.
R3	The Transmission Operator did not inform one other affected Transmission Operator or 5% or less of the other Transmission Operators affected whichever is less of an actual ~~Emergency~~ or anticipated Emergency ~~conditions~~ based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other affected Transmission Operators or more than 5% or less than or equal to 10% of the affected Transmission Operators whichever is less of an actual ~~Emergency~~ or anticipated Emergency ~~conditions~~ based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other affected Transmission Operators or more than 10% or less than or equal to 15% of the affected Transmission Operators whichever is less of an actual ~~Emergency~~ or anticipated Emergency ~~conditions~~ based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis~~.~~. OR The Transmission Operator did not inform four or more other affected Transmission Operators or more than 15% of the affected Transmission operators whichever is less of an actual ~~Emergency~~ or anticipated Emergency ~~conditions~~based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting entity had implemented its comparable

	Lower	Moderate	High	Severe
				emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R5	The ~~responsible entity~~Transmission Operator did not coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas ~~its respective operations known or expected by the Transmission Operator to impact other reliability entities~~ with one affected reliability entity or 5% or less of the affected reliability entities whichever is less when conditions did permit such coordination.	The ~~responsible entity~~Transmission Operator did not coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas ~~coordinate its respective operations known or expected by the Transmission Operator to impact other reliability entities~~ with two affected reliability entities or more than 5% or less than or equal to 10% of the affected reliability entities whichever is less when conditions did permit such coordination.	The ~~responsible entity~~Transmission Operator did not coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas ~~its respective operations known or expected by the Transmission Operator to impact other reliability entities~~ with three affected reliability entities or more than 10% or less than or equal to 15% of the affected reliability entities whichever is less when conditions did permit such coordination.	The ~~responsible entity~~Transmission Operator did not coordinate its operations known or expected to result in an Adverse Reliability Impact on other Transmission Operator Areas ~~its respective operations known or expected by the Transmission Operator to impact other reliability entities~~ with four or more affected reliability entities or more than 15% of the affected entities whichever is less when conditions did permit such coordination.
R6	The responsible entity did not coordinate its respective planned outages of telemetering and control equipment and associated communication channels with one affected reliability entity or 5% or less of the affected entities whichever is less.	The responsible entity did not coordinate its respective planned outages of telemetering and control equipment and associated communication channels with two affected reliability entities or more than 5% or less than or equal to 10% of the affected entities whichever is less.	The responsible entity did not coordinate its respective planned outages of telemetering and control equipment and associated communication channels with three affected reliability entities or more than 10% or less than or equal to 15% of the affected entities whichever is less.	The responsible entity did not coordinate its respective planned outages of telemetering and control equipment and associated communication channels with four or more affected reliability entities or more than 15% of the affected entities whichever is less.
R~~5~~7	N/A	N/A	N/A	The Transmission Operator ~~did not operate within~~ exceeded an identified Interconnection Reliability Operating Limit (IROL) ~~and the~~for a continuous duration greater than its associated IROL T_v ~~for any single occasion~~.
R~~6~~8	The Transmission Operator did not inform its Reliability Coordinator of	The Transmission Operator did not inform its Reliability Coordinator of	The Transmission Operator did not inform its Reliability Coordinator of	The Transmission Operator did not inform its Reliability Coordinator of four

	Lower	Moderate	High	Severe
	one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as support~~s~~ing its local area reliability.	two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as support~~s~~ing its local area reliability.	three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as support~~s~~ing its local area reliability.	or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as support~~s~~ing its local area reliability.
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R9 for a continuous duration greater than 30 minutes.
R~~7~~10	~~The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when one SOL (that supports its local area reliability) has been exceeded~~ N/A	~~The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when two SOLs (that support its local area reliability) have been exceeded.~~ N/A	~~The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when three SOLs (that support its local area reliability) have been exceeded.~~ N/A	The Transmission Operator did not ~~make available evidence that it had~~ inform~~ed~~ its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. ~~OR~~ ~~The Transmission Operator did not make available evidence that it had informed its Reliability Coordinator of actions being taken to return the system to within limits when four or more SOLs (that support its local area reliability) have~~was ~~been exceeded.~~
R~~8~~11	N/A	N/A	N/A	The Transmission Operator did not ~~make available evidence of its~~ act ~~ions~~ or ~~when it~~ direct ~~ed~~ others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v or SOL ~~-~~identified in Requirement R8.
R12	N/A	N/A	N/A	The Transmission Operator did not have monitoring capability, or access to information about, the conditions and Facilities within its Transmission

	Lower	Moderate	High	Severe
				Operator Area.
R13	N/A	N/A	N/A	The Transmission Operator did not monitor, or have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area.
R14	N/A	N/A	N/A	The Transmission Operator's System operator did not have approval rights for planned maintenance of its monitoring and analysis capabilities.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that reliability entities have coordinated plans for meeting expected operating conditions.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

> Rationale for Requirement R1:
>
> By definition, Operational Planning Analysis includes Contingency analysis.
>
> By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have analysis tools or procedures to perform the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, if tools are used, the Transmission Operator must be able to complete the analysis even if those tools are not available.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has planned to preclude operating in excess of the IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL and each SOL identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator does not have an Operational Planning Analysis that represented projected System conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one reliability entity or 5% or less of the reliability entities whichever is less, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two reliability entities or more than 5% and less than or equal to 10% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more reliability entities or more than 15% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Changes pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
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4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. The current draft is the fourth posting of the revised standards and represents one additional posting that was not anticipated. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. Some changes made in this project are dependent on corresponding changes to Project 2006-06, Reliability Coordination, being approved.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	2Q10
2. Post for recirculation ballot.	TBD
3. Submit to BOT.	TBD

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that reliability entities have coordinated plans for meeting expected operating conditions.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

Rationale for Requirement R1:

By definition, Operational Planning Analysis includes Contingency analysis.

By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have analysis tools or procedures to perform the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, if tools are used, the Transmission Operator must be able to complete the analysis even if those tools are not available.

B. Requirements

R1. Each Transmission Operator shall have an ~~assessment~~ Operational Planning Analysis that represents projected System conditions.~~for the next day's operation that indicates whether it will exceed any of its System Operating Limits (SOLs); sduring anticipated normal conditions and potential single Contingency events~~; *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the ~~assessment~~Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of ~~an~~ ~~assessment~~ a completed Operational Planning Analysis ~~for its next day operations~~ in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has planned to preclude operating in excess of the IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the ~~assessment~~Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL and each SOL identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall ~~make available~~have evidence that it notified all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~**1.2.**~~Regional Entity ~~**Compliance Monitoring and Reset Time Frame**~~

~~Not applica~~

~~1.3.~~1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.4.~~1.3. Data Retention

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month ~~-~~period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer~~.~~.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

~~1.5.~~1.4. Additional Compliance Information

None.

2. **Violation Severity Levels**

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator does not have an ~~assessment~~Operational Planning Analysis that represented projected System conditions. ~~for the next day's operation ededduring anticipated normal and potential single Contingency event conditionsand its.~~
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the ~~assessment~~Operational Planning Analysis performed in Requirement R1.
R3	The Transmission Operator did not notify one reliability entity or 5% or less of the reliability entities whichever is less, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two reliability entities or more than 5% and less than or equal to 10% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more reliability entities or more than 15% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
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1	November 1, 2006	Adopted by Board of Trustees	Revised
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Standard Development Roadmap

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	2Q10
2. Post for recirculation ballot.	TBD
3. Submit to BOT.	TBD

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Owners.

   4.4. Generator Operators.

   4.5. Interchange Authorities.

   4.6. Load-Serving Entities.

   4.7. Transmission Owners.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of required data to be exchanged including, but not limited to:

- Long term outages of Bulk Electric System equipment, as specified by the Transmission Operator or Balancing Authority.
- Operating parameters for equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.

1.2. A mutually agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities, the data requested by those other Transmission Operators and Balancing Authorities necessary for Operational Planning Analysis and Real-time monitoring. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R1.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

Regional Entity

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall retain evidence for 90 calendar days that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4 and Measurement M4.
- Each Transmission Operator and Balancing Authority shall retain evidence for 90 calendar days that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-Time operations in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The responsible entity did not have one of the required elements of the documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not have two of the required elements of the documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring.	N/A	The responsible entity did not have a documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring.
R2	The Transmission Operator did not distribute its data specification to one reliability entity or 5% or less of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or to one reliability entity or 5% or less of the entities whichever is less, that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to two reliability entities or more than 5% and less than or equal to10% of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or to two reliability entities or more than 5% and less than or equal to 10% of the entities whichever is less, that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to four or more reliability entities or more than 15% of the entities whichever is less, that have Facilities monitored by the Transmission Operator or four or more of the reliability entities or more than 15% of the reliability entities whichever is less,that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to one reliability entity or 5% or less of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to one reliability entity or 5% or less of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to two reliability entities or more than 5% and less than or equal to 10% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to two reliability entities or more than 5% and less than or equal to 10% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to three reliability entities or more than 10% and less than or equal to 15% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to four or more reliability entities or more than 15% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to four or more reliability entities or more than 15% of the reliability entities whichever is less,that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R2 or R3 did not satisfy the obligations of the

				documented specifications for data.
R5	N/A	N/A	N/A	The responsible entity did not provide to other Transmission Operators or Balancing Authorities the data and information requested by those entities necessary for Operational Planning Analysis and Real-time monitoring.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
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A. Introduction

1. Title: **Operational Reliability Data**

2. Number: TOP-003-2

3. Purpose: To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.

4. Applicability

4.1. Transmission Operators.

4.2. Balancing Authorities.

4.3. Generator Owners.

4.4. Generator Operators.

4.5. Interchange Authorities.

4.6. Load-Serving Entities.

4.7. Transmission Owners.

5. Effective Date: All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall have a documented specification for the data necessary for ~~them~~it to perform ~~their~~its required ~~Real-time monitoring and reliability assessments~~Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of required data to be exchanged including, but not limited to:

- Long term outages of Bulk Electric System equipment, as specified by the Transmission Operator or Balancing Authority~~,~~.
- Operating parameters for ~~E~~equipment at voltage levels lower than the Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority.

1.2. A mutually agreeable format.

1.3. A ~~timeframe and~~ periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities, the data requested by those other Transmission Operators and Balancing Authorities necessary for ~~Real-time monitoring and reliability assessments~~Operational Planning Analysis and Real-time monitoring. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R1.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data ~~-~~in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for ~~reliability assessments~~ Operational Planning Analysis and Real-time operation in accordance with Requirement R5. ~~Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail record~~The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

~~1.2.~~Regional Entity ~~**Compliance Monitoring Period and Reset Timeframe**~~

~~Not applicab~~

~~1.3.~~1.2. **Compliance Monitoring and Enforcement Processes**

Compliance Audits

Self-Certification

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~1.4.~~1.3. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Operational Planning Analyses ~~Real-time monitoring and reliability assessments~~ and Real-time monitoring in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall retain evidence for 90 calendar days that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4 and Measurement M4.
- Each Transmission Operator and Balancing Authority shall retain evidence for 90 calendar days that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for ~~reliability assessments~~Operational Planning Analysis and Real-Time operations in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

~~1.5.~~1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The responsible entity did not have one of the required elements of the documented specification for the data necessary for them to perform their required Operational Planning Analyses ~~Real-time monitoring and reliability assessments~~ and Real-time monitoring.	The responsible entity did not have two of the required elements of the documented specification for the data necessary for them to perform their required Operational Planning Analyses ~~Real-time monitoring and reliability assessments~~ and Real-time monitoring.	N/A	The responsible entity did not have a documented specification for the data necessary for them to perform their required Operational Planning Analyses ~~Real-time monitoring and reliability assessments~~ and Real-time monitoring.
R2	The Transmission Operator did not distribute its data specification to one reliability entity or 5% or less of the reliability entities whichever is less, that ~~has~~have Facilities monitored by the Transmission Operator or to one reliability entity or 5% or less of the entities whichever is less, that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to two reliability entities or more than 5% and less than or equal to10% of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or to two reliability entities or more than 5% and less than or equal to 10% of the entities whichever is less, that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to four or more reliability entities or more than 15% of the entities whichever is less, that have Facilities monitored by the Transmission Operator or four or more of the reliability entities or more than 15% of the reliability entities whichever is less,~~-~~that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to one reliability entity or 5% or less of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to one reliability entity or 5% or less of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to two reliability entities or more than 5% and less than or equal to 10% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to two reliability entities or more than 5% and less than or equal to 10% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to three reliability entities or more than 10% and less than or equal to 15% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to four or more reliability entities or more than 15% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to four or more reliability entities or more than 15% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The responsible entity receiving a data

				specification in Requirement R2 or R3 did not satisfy the obligations of the documented specifications for data.~~.~~
R5	N/A	N/A	N/A	The responsible entity did not provide to other Transmission Operators or Balancing Authorities the data and information requested by those entities necessary for ~~real-time monitoring and reliability assessments~~Operational Planning Analysis and Real-time monitoring.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

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Implementation Plan for Project 2007-03: Real-Time Operations

Prerequisite Approvals

Some changes made in this project are dependent on corresponding changes being approved in Project 2006-06, Reliability Coordination:

- COM-001-1 — Telecommunications
- COM-002-2 — Communications and Coordination
- IRO-001-1 — Reliability Coordination — Responsibilities and Authorities
- IRO-002-1 — Reliability Coordination — Facilities
- IRO-014-1 — Procedures to Support Coordination between Reliability Coordinators
- IRO-015-1 — Notifications and Information Exchange between Reliability Coordinators
- IRO-016-1 — Coordination of Real-Time Activities between Reliability Coordinators
- PER-004-1 — Reliability Coordination — Staffing
- PRC-001-1 — System Protection Coordination

It is the intent of the SDT that Project 2006-06 and Project 2007-03 be filed together so that the changes to the different standards can be coordinated.

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

However, three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated on a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

Compliance with Standard

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							
TOP-001-2: Coordination of Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X		X
TOP-004-2: Real-Time Transmission	Retired							

Operations	
TOP-005-2: Operational Reliability Data	Retired
TOP-006-1: Monitoring System Conditions	Retired
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired
TOP-008-1: Response to Transmission Limit Violations	Retired

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

The assumption used by the SDT in establishing this Implementation Plan is that the project mentioned in the prerequisites: Project 2006-06, Reliability Coordination; has been approved prior to the implementation of this Project 2007-03, Real-Time Operations.

Effective Date of Revised Standards
All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

Retirement Date for Existing Standards
All requirements will be retired twenty-four months following the first day of the first quarter following regulatory approval.

Mapping Table

The following table indicates the disposition of the existing standards related to this project.

Existing Requirement	Resolution
TOP-001-1	
R1	Deleted – Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. Needed actions required for reliability of the bulk power system have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement.
R2	Deleted for Reliability Coordinator - The Reliability Coordinator has the ultimate responsibility for the reliability of the bulk power system and the Transmission Operator must respond to Reliability Coordinator directives as per proposed IRO-001-2, Requirement R2.

	Replaced for Transmission Operator – Based on the interpretation of the undefined term 'operating emergency' as equivalent to 'Emergency' as defined in the Glossary which points to 'Adverse Reliability Impact' which in turn points to IROLs, this has been replaced by proposed TOP-001-2, Requirements R7 through R10.
R3	Moved for Reliability Coordinator - All references to the Reliability Coordinator and Reliability Coordinator responsibilities have been removed from the TOP standards as they are now covered in the revisions being undertaken in Project 2006-06. This requirement is now covered in the proposed IRO-001-2, Requirements R2 & R3. Replaced for Transmission Operator – Proposed TOP-001-2, Requirement R1 now covers the Balancing Authority and Generator Operator responding to Transmission Operator directives.
R4	Retained and moved to proposed TOP-001-2, Requirement R1.
R5	Retained and moved to proposed TOP-001-2, Requirement R2. The intent of the "mitigation" phrasing was replaced by proposed TOP-001-2, Requirement R10. (Also, see explanation for R2 above.) Also, this is covered in approved EOP-001-0, Requirement R3 and the proposed EOP-001-2, Requirement R2.
R6	Retained and moved to proposed TOP-001-2, Requirement R3 for the Transmission Operator. The Generator Operator was removed since they can't be contacted directly by others and will only respond to such requests if they were in the form of a Reliability Directive from its Transmission Operator which is covered in proposed TOP-001-2, Requirement R1. EOP-001-0, Requirement R1 covers the Balancing Authority so to eliminate a redundancy the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission Operator as stated in proposed TOP-001-2, Requirement R1.
R7	Retained in concept but re-worded as part of proposed TOP-001-2, Requirements R4 & R5. After the fact notifications have been deleted since those actions will be seen through telemetry as cited in the proposed TOP-003-2 and proposed IRO-001-2. The term 'burden' was considered by the SDT to be vague, ambiguous, unmeasurable, and undefined and has been replaced by a NERC defined term 'Burden'.
R8	Real Power Balance and Reactive Power Balance are not defined terms. First sentence – Deleted due to: - The Balancing Authority is covered in approved EOP-002-2.1, Requirement R6. Therefore, this portion of the requirement is superfluous and can be deleted. The Transmission Operator does not balance real power so that part of the sentence can be deleted. Approved VAR-001-1, Requirement R8 covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and can therefore be deleted from this part of the requirement. Second sentence – Deleted due to: The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and can thus be deleted. Transmission Operators are covered under approved VAR-001-1, Requirement R1 thus making this part of the requirement redundant. Third sentence – The Reliability Coordinator is now covered in proposed IRO-009-1, Requirements R1 through R4 and can be deleted here. The Transmission Operator and Balancing Authority are covered in approved EOP-003-1, Requirement R1. Therefore, this is redundant and can be deleted.
TOP-002-2	

R1	First sentence – Deleted for Balancing Authority, Retained for Transmission Operator - The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-0 and must take action per approved EOP-002-2.1, Requirement R6 and thus can be deleted. Retained for Transmission Operator in proposed TOP-002-3, Requirements R1 through R3. This is patterned after the proposed IRO-008-1, Requirement R1 for the Reliability Coordinator. Second sentence – Deleted. The Balancing Authority is covered in approved BAL-002-0, Requirement R3 and thus is redundant and can be deleted here. The Transmission Operator is covered in the proposed TOP-001-2, Requirement R10 and is thus also redundant and can be deleted. In addition, approved EOP-001-2, Requirement R3 covers the Transmission Operator having plans in place to mitigate emergency conditions.
R2	Deleted - The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted.
R3	For all but the Transmission Service Provider, proposed TOP-003-2 requires the transfer of any and all data required for Real-time operations or Operational Planning Analyses regardless of timeframe involved. That makes this requirement redundant and it can be deleted. The Transmission Service Provider is covered in the proposed MOD-028-1, MOD-029-1, and MOD-030-1 and is thus redundant and can be deleted.
R4	Deleted – Proposed TOP-003-2 requires the transfer of any and all data required for Real-time operations or Operational Planning Analyses between and amongst Balancing Authorities and Transmission Operators regardless of timeframe involved. That makes this requirement redundant and it can be deleted for Balancing Authorities and Transmission Operators. Data requirements for Reliability Coordinators are covered in proposed IRO-010-1, Requirement R3 making this requirement redundant for Reliability Coordinators and it is therefore deleted.
R5	The Balancing Authority is covered by approved BAL-001-0.1a and thus can be deleted. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2. Transmission Operator - replaced by proposed TOP-002-3, requirements R1 through R3.
R6	The Balancing Authority is covered by approved BAL-002-0, Requirements R2 through R4 and approved EOP-002-2.1, Requirement R6 and thus can be deleted. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2.

	Transmission Operator - replaced by proposed TOP-002-3, Requirements R1 through R3. The SDT does not believe that there is a need for the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. As stated in the NERC Functional Model V4, the Balancing Function: "Integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area and supports Interconnection frequency in real time." To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and BAL-002-0, Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any system condition. Balancing Authorities are not responsible for the operation of the transmission system. The Transmission Operator is responsible for the real-time operating reliability of the transmission assets under its purview, and as such has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding load, generation and interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or load shedding). If the Balancing Authorities' actions do not resolve the transmission issues, it is the Transmission Operators' or Reliability Coordinators' responsibility to direct alternative actions.
R7	The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0, Requirement R2 and therefore this requirement is redundant and can be deleted. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirements R1 and R2. Operational Planning Analysis includes deliverability considerations.
R8	Deleted - The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and thus this requirement can be deleted. Voltage and reactive are the responsibility of the Transmission Operator and are covered under approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1 and R2.
R9	This is covered in approved INT-003-2 and is redundant and can be deleted.
R10	Balancing Authority - deleted as for transmission, the Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the Glossary and thus this requirement is not applicable to the Balancing Authority. The SDT position is that SOLs and IROLs are transmission items for which the Balancing Authority has no information or control. The Transmission Operator instructs the Balancing Authority as to what to do in these situations. Transmission Operator - covered in proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs. As stated in the NERC Functional Model V4, the Balancing Authority is responsible for integrating resource plans ahead of time, maintaining load-interchange-generation balance within a Balancing Authority Area and supporting Interconnection frequency in real time. The Balancing Authority does not possess the bulk power system information necessary to manage transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator.
R11	Deleted: First sentence – Proposed TOP-003-2 requires the transfer of any and all data required for real-time operations or Operational Planning Analyses regardless of the timeframe involved. Operational Planning Analyses are covered in proposed TOP-002-3, Requirement R1. Second sentence deleted as this is now covered in the proposed IRO-009-1, Requirement R5 for

	IROLs and the SDT has moved toward an operating philosophy for the Transmission Operator based on avoiding IROLs (and selected SOLs) and acting within the IROL T_v. Third sentence – 'update… as necessary' is ambiguous and the SDT believes that proposed TOP-003-2, Requirement R1 better covers this for studies and covered in proposed TOP-002-3, Requirement R3 for distribution so this is redundant and can be deleted.
R12	Deleted as duplicative of proposed MOD-028-2, MOD-029-2, or MOD-030-2 .
R13	Deleted as duplicative of approved FAC-008-1 & approved FAC-009-1, Requirement R1.3.
R14	Deleted – duplicative of proposed TOP-003-2.
R15	Deleted – duplicative of proposed TOP-003-2.
R16	Deleted – duplicative of proposed TOP-003-2.
R17	Deleted - duplicative of proposed IRO-010-1, Requirement R3.
R18	Deleted as the SDT feels that this requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The SDT feels that the true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19	Deleted - Order 693, paragraph 1660 states that FERC is not interested in analytical tools but rather in capabilities. This requirement is tool-specific and as such is not suitable for Reliability Standards per Order 693.
TOP-003-1	
R1	Deleted as duplicative of proposed TOP-003-2, Requirement R1.
R2	Balancing Authority deleted since Balancing Authority is only required to respond to Reliability Directives regarding voltage. Proposed TOP-001-2, Requirement R4 covers coordination issues. Proposed TOP-003-2, Requirement R1 handles data requirements.
R3	Retained as proposed TOP-001-2, Requirement R6.
R4	Deleted – covered by proposed TOP-001-2, Requirements R4 & R5 as the SDT expects the entities to resolve any conflicts based on this requirement. If the conflict can't be resolved, the (proposed) IRO-001-2, Requirement R1 gives the Reliability Coordinator the authority to resolve the conflict. .
TOP-004-2	
R1	Moved to proposed TOP-001-2, R7 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.
R2	Moved to proposed TOP-001-2, Requirement R7 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.
R3	Moved to proposed TOP-001-2, Requirement R7. This requirement is not limited by single or multiple Contingencies but is based solely on identified IROLs regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator.
R4	Deleted due to the fact that the SDT believes the best way to handle such a situation is to treat it

	like an IROL or restoration scenario and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is covered under proposed TOP-001-2, Requirement R7 and the proposed EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power system.
R5	The Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, thus the first sentence is a moot point and that portion of the requirement can be deleted. The second sentence has been replaced by proposed TOP-001-2, R7 through R10 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.
R6	The first sentence was deleted as it is has been superseded by the NERC Reliability Standards taken as a whole. The second sentence can be deleted as all of the sub-requirements are covered elsewhere: R6.1 is duplicative of approved VAR-001-1, Requirement R1 for reactive. Real power flows are covered in proposed TOP-001-2, Requirement R7. R6.2 is covered in proposed TOP-001-2, Requirement R4 R6.3 – moved to proposedTOP-001-2, Requirement R4; R6.4 – moved to proposed TOP-001-2, Requirements R7 through R10 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v. Also, a Transmission Operator must have a documented Operating Procedure covering every applicable standard requirement in order to pass an audit
TOP-005-2	
R1	Confidentiality is not a reliability issue but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.
R2	Deleted – covered by proposed TOP-003-2.
R3	Deleted –All operating data that a Purchasing Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system. This is a NAESB standard and can thus be deleted. Purchasing Selling Entity is covered under the INT standards and thus can be deleted.
TOP-006-2	
R1	R1 & R1.1 - Deleted – covered as part of the new data specification requirements in proposed TOP-003-2. R1.2 - Deleted – covered by proposed IRO-010-1, Requirement R3.
R2	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by proposed IRO-010-1, Requirement R3.
R3	Deleted – as duplicative of proposed PER-005-1 (training) and proposed TOP-003-2 (data).
R4	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2.
R5	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, for Transmission Operator avoiding IROLs; proposed IRO-008-1, Requirement R2 for real-time assessments every 30 minutes for Reliability Coordinators.

R6	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-o.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, for Transmission Operator avoiding IROLs.
R7	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, for Transmission Operator avoiding underfrequency; proposed EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators.
TOP-007-0	
R1	Moved to proposed TOP-001-2, R9 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.
R2	Moved to proposed TOP-001-2, R7 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.
R3	Deleted - Covered in approved EOP-003-1, Requirements R1 & R3. and proposed TOP-001-2, Requirement R10.
R4	Deleted as duplicative of approved IRO-001-1.1, R3.
TOP-008-1	
R1	Deleted – as duplicative of approved EOP-003-1, Requirements R1, R3 & R5 and proposed TOP-001-2, Requirement R10.
R2	First sentence - Deleted as duplicative of proposed TOP-001-2, Requirement R7 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v. Second sentence – deleted as this is now handled by the Reliability Coordinator as cited in proposed IRO-009-1, Requirement R5.
R3	Delete first sentence – Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. If the situation involves an IROL it is covered in proposed TOP-001-2, Requirements R7 through R10. If it is not an IROL, then the owner still has the right to protect their equipment within the limitations of their contracts and obligation to comply with the Reliability Standards. Delete second sentence as duplicative of proposed TOP-001-2, Requirements R4 & R5. The SDT feels that a standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on system conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse.
R4	Deleted – information is covered as part of the new data specification requirements in proposed TOP-003-2. Analysis tools are covered in the certification process for initial core capabilities. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Operational Planning Analyses are required in proposed TOP-002-3 while real-time analysis is required for IROL mitigation in proposed TOP-001-2 thus covering the operational timeframes. Proposed TOP-001-2, R10 covers mitigation of limit violations with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.
PER-001-0	

R1	Deleted - In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.

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Resolution of Issues Assigned to Real-time Operations SDT (Project 2007-03)

Standard	Source	Language	Resolution
TOP-001			
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	This is covered in proposed TOP-001-2, Requirement R5.
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	Requirement using this term was deleted as not needed in a reliability standard. The standards already require the necessary actions.
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been re-written to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this

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Standard	Source	Language	Resolution
			regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-002			
TOP-002-2	FERC Order 693	1600 - Address critical energy infrastructure confidentiality as part of the routine standard development process.	Restrictions due to confidentiality have been eliminated by re-writing the data specification requirements in proposed TOP-003-2.
TOP-00-2	FERC Order 693	1601 – Require next day analysis for all IROLs to identify and communicate control actions to system operators	See proposed TOP-002-3, Requirements R1, R2, and R3.
TOP-002-2	FERC Order 693	1603 - Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-002-2	FERC Order 693	1604/1608 - Requires simulation contingencies to match what will actually happen in the field.	To the extent possible, this is covered in proposed TOP-002-3, Requirement R1 by the phrase “and shall represent projected System conditions”.
TOP-002-2	FERC Order 693	1606 - Commenters did not take issue with the proposed interpretation of the term “deliverability” as “the ability to deliver the output from generation resources to firm load without any	Deliverability and limits are implicitly included in Operational Planning Analysis in TOP-002-3, Requirement R1.

Standard	Source	Language	Resolution
		reliability criteria violations for plausible generation dispatches."[1] The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	
TOP-002-1	Fill in the Blank Team	Remove "in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements" from R6 and "in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes" from R12 .	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. Requirement R12 has been deleted as duplicative of MOD-030-2 (not yet approved).
TOP-002-2: R19	NERC Audit Observation Team	How do you address the term - verify "Accurate"	Requirement R19 was eliminated as unmeasurable.
TOP-002-2	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1.
TOP-002-1	Version 0 Team	Define N-1	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. This term is no longer in use for this standard.
TOP-002-1	Version 0 Team	Define 'without intentional delay'	This term was considered unmeasurable and has been deleted from this standard.

[1] Id. at P 974.

Standard	Source	Language	Resolution
TOP-002-1	Version 0 Team	Reliability should 'trump' confidentiality	The SDT has removed all references to confidentiality by re-writing the data specification requirements.
TOP-002-1	Version 0 Team	Coordination of planning required	The SDT has re-written and tightened up the requirements for distributing data and information.
TOP-002-1	Version 0 Team	Limit of 2 tests per year	This requirement has been deleted by the SDT as verification testing is not needed in this standard.
TOP-002-1	VRF Team	R9 – related to INT-003	Requirement R9 has been deleted as it is duplicative of approved INT-003-2
TOP-002-1	VRF Team	R14 & 14.1 – ambiguous	Deleted – duplicative of proposed TOP-003-2.
TOP-002-1	VRF Team	R2 – administrative in nature, not a real requirement	The SDT agreed and deleted this requirement.
TOP-003			
TOP-003-0	FERC Order 693	1620 & 1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	The SDT posed a question on this issue as a fact finding exercise in the second posting of this project in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. After reviewing the industry comments, the SDT concluded that proposed TOP-001-2, Requirements R5 & R6 adequately cover this issue. The SDT bases this position on the requirement which includes the Operations

Standard	Source	Language	Resolution
			Planning Time Horizon that covers the period from one day to one year. The requirement mandates that actions are coordinated. The SDT interprets this to include planned outages when they are known. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	FERC Order 693	1622 - Consider TVA's suggestion for including breaker outages within the meaning of facilities that are subject to advance notice for planned outages.	New data specifications in proposed TOP-003-2 handle this concern. Note – For this and other issues noted as handled by the new data specification standard: FERC staff has indicated that they do not agree with this approach as an equal and effective substitute for the approved requirements.
TOP-003-0	FERC Order 693	1624 - Require any facility, that in the opinion of the reliability coordinator, balancing authority, or transmission operator, will have a direct impact on the reliability of the bulk power system be subject to the requirement R1 for planned outage coordination.	New data specifications in proposed TOP-003-2, Requirement R1 (and bullets) handle this concern.
TOP-003-0	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1
TOP-003-0	Version 0 Team	Outage information needed sooner than 1 day prior	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	Version 0 Team	RA can't request outage cancellation	Deleted – now covered in Project 2006-06.
TOP-003-0	Version 0 Team	Submit outage data ASAP but no later than noon day ahead	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	VRF Team	R4 – poorly written	Deleted – now covered in Project 2006-06.
TOP-003-1	FMPA – Frank Gaffney	With respect to requirement R1.2, why is the TOP responsible for providing generator outage	Requirement deleted as duplicative of proposed TOP-003-2, R1.

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Standard	Source	Language	Resolution
		information? Isn't that the BA's or GOP's responsibility and isn't this redundant with IRO-010-1?	
TOP-004			
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	Replaced by proposed TOP-001-2, R8 through R11 with the note that the SDT has moved toward an operating philosophy based on identifying, avoiding, mitigating, and responding to IROLs and the IROL T_v. T_v is more stringent than the existing 30 minute requirement. Unknown states, in this context, cannot exist because valid operating limits have been determined for all Facilities in a TOP's footprint. The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to emergencies.
TOP-004-1	FERC Order 693	1637 - Reliability coordinators should report any IROL violations to NERC on a monthly basis for one year beginning August 2, 2007.	Not within the scope of the SDT.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (. . .the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process	The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the bulk power system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		should develop a procedure to identify applicable high risk conditions. Under . . . high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	FERC Order 693	1639 - Consider Santa Clara's comments regarding changes to requirement R2 in the standards development process. (Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.)	This is covered as part of the new data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by proposed IRO-010-1, Requirement R3.
TOP-004-1	FERC Order 693	1641 - NERC should report the results of the survey to the Commission within 18 months of the effective date of this rule.	Not within the scope of the SDT.
TOP-004-1	Fill in the Blank Team	No action required	No action required.
TOP-004-1	Version 0 Team	Operations should conform to planning standards	Operations and planning are different timeframes with different problems and solutions
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	Requirement moved to proposed TOP-001-2, Requirement R5 and clarified.
TOP-004-1	Version 0 Team	Define SOL & IROL	These are defined terms in the NERC Glossary.
TOP-004-1	Version 0 Team	Clarify roles	Applicability has been reviewed and updated as necessary.
TOP-004-1	Version 0 Team	Define (or remove) practical	The term has been removed.
TOP-004-1	Version 0 Team	Specify disconnection as acceptable in R5	The requirement has been deleted. Relationships between the Reliability Coordinator and Transmission Operator as described in the revised standards cover these actions.

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Standard	Source	Language	Resolution
TOP-005			
TOP-005-1	FERC Order 693	1648 - Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.
TOP-005-1	FERC Order 693	1649 - Delete references to confidentiality agreements but ensure critical energy infrastructure confidentiality is addressed in the standards development process.	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	FERC Order 693	1650 - Consider FirstEnergy's modifications to Attachment 1 and ISO-NE's recommended revision to requirement R4 in the standards development process. ISO-NE recommends that the reference to "purchasing-selling entity" in Requirement R4 should be replaced with "generator owner, transmission owner, and LSE.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2. Requirement R4 has been superseded by proposed TOP-003-2 which does include the indicated entities.
TOP-005-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R2 of PRC-001-1 in TOP-005. Note: These requirements are being removed from PRC.	See proposed TOP-003-2, Requirement R1
TOP-005-1	Version 0 Team	Need to include GO & LSE	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Data update is too slow	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Generator data should include voltage control & stabilizers	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	GO needs to supply data to BA & TO	New data specifications in proposed TOP-003-2 handle this concern
TOP-005-1	Received for the November 4, 2009	NERC staff believes that the interpretation does not support the stated purpose of IRO-005-1:	While this issue was entered against the Transmission Operator as the interpretation request was primarily for TOP-005-1, the emphasis on such

Standard	Source	Language	Resolution
	Technical Conference on Interpretations of Standards from Manitoba Hydro	”The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.” Given that Requirement R12 pre-supposes that the SPS is armed to address inter-Balancing Authority or inter-Transmission Operator impacts (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), the argument not discussed in the interpretation is that the SPS itself with one communication channel in service can be viewed for advance planning or reliability assessment purposes as a single contingency (loss of the communication channel). The question asked by the requestor indicates that the operation of the SPS on a single channel is known ahead of the timeframe for which the SPS may be armed and that the condition was not first identified when the SPS was called to operate. In this regard, the Reliability Coordinator must be aware of the less dependable state of the SPS in order to properly assess the impact and plan for the next single contingency that it conceivably could experience. In this case, the Reliability Coordinator may wish to consider the loss of an armed SPS when performing its reliability assessments. While the Reliability Coordinator may not elect to proactively position the system to withstand the loss of the SPS that is operating on a single communication channel, the Reliability Coordinator may elect to develop a contingency plan in the event the SPS does fail to operate as designed or if the remaining	informative actions has shifted in current revision projects. The proposed IRO-010-1, Requirement R1 gives the Reliability Coordinator the right to ask for any reliability related data that they need to perform their Reliability Coordinator task. And it also mandates the Transmission Operator to provide said data in Requirement R3. (Note – This standard has been approved by the BOT but has not yet been approved by FERC.)

Standard	Source	Language	Resolution
		communication channel is lost. The importance of the SPS relative to current or anticipated system conditions would be considerations for the Reliability Coordinator. This consideration only becomes possible if the Transmission Operator notifies the Reliability Coordinator that the SPS is operating on a single communication channel. Therefore, Transmission Operator notification to the Reliability Coordinator of this condition raises the Reliability Coordinator's situational awareness that may influence current or future operating conditions or decisions in a preventive rather than reactive manner. NERC staff does agree that the SPS is still mission capable with only one communication channel in service, but degraded in terms of its dependability due to the unavailability of redundant communications channels. The fact that a second communications channel was part of the original design of the SPS suggests that both channels were important to the dependability of the system, and that the unavailability of either channel causes some degradation in the overall dependability of the SPS. Additionally, the team equated "any degradation" with "potential failure to operate as expected" in IRO-005. The use of the term "or" connecting these two phrases in the standard indicates these were not intended to be equivalent. Therefore, NERC staff believes the conclusion reached by the team that the two terms are synonymous is incorrect. Further, the specific circumstances contemplated in the interpretation request are not likely to occur often and the additional burden to Transmission Operators to notify the Reliability Coordinator is de minimis when compared to the improved	

Standard	Source	Language	Resolution
		situational awareness that would result. On this basis, NERC staff believes the interpretation is not serving the best interests of reliability and should be remanded to the team for further consideration of the NERC staff opinion.	
TOP-006			
TOP-006-1	FERC Order 693	1660 & 1661 - Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system.	TOP-001-2, Requirements R11 through R13 cover the minimum capability issue. Requirement for phase angle information is covered by proposed TOP-003-2.
TOP-006-1	FERC Order 693	1663 - Clarify the meaning of "appropriate technical information" concerning protective relays. To provide more clarity, criteria that define what "appropriate technical information" is necessary should be specified so that operators can make better informed decisions.	This term is no longer used. Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and TOP-003-2 (data).
TOP-006-1	FERC Order 693	1664 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
TOP-006-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R6 of PRC-001-1 in TOP-003 R5 or TOP-006. Note: These requirements are being retired in PRC-001-1.	See proposed TOP-003-2, Requirement R1
TOP-006-1	Version 0 Team	Need to match roles with FM	Applicability has been reviewed by the SDT and changed as required in accordance with the FM and the Compliance Registry.
TOP-006-1	Version 0 Team	Monitor frequency at multiple points	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	Load forecasting data required	New data specifications in proposed TOP-003-2 handle this concern.

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Standard	Source	Language	Resolution
TOP-006-1	Version 0 Team	GO needs to provide normal & emergency data	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R1, 1.1, 1.2 – 'available in emergency situation' may be needed	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R3 – define appropriate	This requirement was deleted as duplicative of approved PRC-001-1, Requirement R1.
TOP-006-1	VRFs Team	R4 – What information is required and what is a load pattern?	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirements R1 and R1.2, why are BAs responsible for information regarding transmission resources available for use? Isn't that the role of the TOP?	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R2, why is the BA responsible for monitoring transmission line status, voltage, load tap changer settings, and reactive power in general? Monitoring and managing reactive resources, voltage and tap settings is clearly made the responsibility of the TOP in VAR-001-1a.	Deleted – SDT agrees.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R3 why does the BA need to understand protective relaying? Isn't that the role of the TOP and GOP?	Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and proposed TOP-003-2 (data).
TOP-007			
TOP-007-0	FERC Order 693	1673 - Consider the NRC's comments on voltage requirements as part of the standards development process.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2.

Standard	Source	Language	Resolution
			Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-007-0	Version 0 Team	Need to define evidence of evaluation	This term isn't used in the requirements – no action required.
TOP-007-0	Version 0 Team	Need to tighten the non-compliance terms	Measures and VSL have been assigned to all requirements.
TOP-007-0	Version 0 Team	Not enforceable with current criteria	Not enough information provided to address concern.
TOP-007-0	Version 0 Team	RA should be included	Reliability Coordinator is now covered in Project 2006-06.
TOP-007-0	Version 0 Team	More of a compliance issue than a true standard	Not enough information provided to address concern.
TOP-008			
TOP-008-1	FERC Order 693	1681 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
PER-001			
PER-001-0	Version 0 Team	Data retention should be 1 year	This standard will be retired.

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for each requirement in TOP-001-2 — Coordination of Transmission Operations, TOP-002-3 — Operations Planning, and TOP-003-2 — Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of VRF in TOP-001-2, TOP-002-2, and TOP-003-2:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions

anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

> Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are thirteen requirements in TOP-001-2. None of the thirteen requirements were assigned a "Lower" VRF. Requirements R1, R2, R3, R4, R8, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Inability to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions: IRO-001-2 for a Reliability Coordinator and TOP-001-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render emergency assistance could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-014-2 that is assigned a Medium VRF. The

requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities: TOP-001-2 for Transmission Operators and IRO-014-2 for Reliability Coordinators. The assignment of the Medium VRF was made based on the premise that failure to coordinate activities, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to coordinate activities. While the SDT agrees that, under some circumstances, it is possible that a failure to coordinate activities may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to coordinate would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to coordinate activities, it would still be expected to handle the situation if it occurred.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R7 has been assigned a Medium VRF and is the replacement (and a copy of) for approved TOP-003-1, Requirement R3.which was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or cascading failures
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R7 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R8 mandates that entities operate within each identified IROL and its associated IROL T_v. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R9 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R8. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, Requirement R8 which has a High VRF. If the Transmission Operator failed to notify the Reliability Coordinator of actions to alleviate a specific SOL that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R8. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, Requirement R8 and this requirement is a simple notification requirement for informational

purposes only. Therefore, bulk power system instability, separation, or cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.

- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. Therefore, there is consistency among Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities operate within each identified IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved IRO-002-1, Requirement R8 which has a High VRF. Therefore, there is consistency among Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that a Transmission Operator shall monitor the conditions and Facilities within its Transmission Operator Area. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are more likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R12:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R12 is a new requirement, so there are no comparable requirements with which to compare

VRFs. However, it is similar to approved IRO-001-1, Requirement R8 which has a High VRF. Therefore, there is consistency among Reliability Standards.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that a Transmission Operator shall monitor the conditions and Facilities external its Transmission Operator Area subject to certain constraints. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are more likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R12 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R13:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R13 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved IRO-002-1, Requirement R9 which has a Medium VRF. Therefore, there is consistency among Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R13 mandates that entities have control over planned outages of their monitoring and analysis capabilities. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are unlikely to occur. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R13 addresses a single objective and has a single VRF.

There are three requirements in TOP-002-3. None of the three requirements were assigned a "Lower" VRF. Requirement R2 was assigned a "High" VRF while Requirements R1 & R3 were given a "Medium" VRF.

VRF for TOP-002-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-008-1 that is also assigned a Medium VRF. The requirements are viewed as similar since they both refer to preparing an Operational Planning Analysis: IRO-008-1 for a Reliability Coordinator and TOP-002-3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So, while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R2 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to preclude operating in violation of limits could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R3 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of their roles in mitigating potential problems does not, in and of itself, lead to bulk power system instability, separation or cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3 Requirement R3 contains only one objective, therefore only one VRF was assigned.

There are five requirements in TOP-003-2. Three of the five requirements were assigned a "Lower" VRF - Requirements R1, R2, and R3. Requirements R4 and R5 were assigned a "Medium" VRF.

VRF for TOP-003-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-010-1 that is also assigned a Low VRF. The

requirements are viewed as similar since they both refer to data specifications: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-010-1 that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-010-1 that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Low VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-010-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. However, it greatly increases the likelihood of such problems and therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-010-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. However, it greatly increases the likelihood of such problems and therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

Justification for Assignment of VSLs for TOP-001-2, TOP-002-2, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

> Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

> A violation of a "binary" type requirement must be a "Severe" VSL.
>
> Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

> VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

> . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R2. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R4. Those VSLs are also based on failure to notify reliability entities in a graduated scale from Lower to	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
	violations.	Severe. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the proposed IRO-014-2, Requirement R1. Those VSLs are also based on a graduated scale from Lower to Severe. The VSLs assignments are similar between the two standards. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
		for the VSL and assigned the VSLs appropriately.			

VSLs for TOP-001-2 Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R8.	Meets NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with	The VSL is based on a single violation and not cumulative violations.

			violations.	the requirement.	

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R9.	Meets NERC's VSL guidelines.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		already proposed.			

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs but it is similar to approved IRO-002-1, Requirement R8. That is a multiple part requirement but the VSL for the part dealing with monitoring is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R12:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R12.	Meets NERC's VSL guidelines -	The proposed requirement is new and	The proposed VSL does not use any ambiguous terminology,	The proposed VSL uses the same terminology as used	The VSL is based on a single violation and

	Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	there are no comparable VSLs but it is similar to approved IRO-002-1, Requirement R8. That is a multiple part requirement but the VSL for the part dealing with monitoring is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	in the associated requirement, and is, therefore, consistent with the requirement.	not cumulative violations.

VSLs for TOP-001-2 Requirement R13:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R13.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs but it is similar to approved IRO-002-1, Requirement R9. That VSL is incremental. However, the SDT felt that this requirement, while similar but not exactly the same, warranted a binary VSL. Thus, the VSL in the	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-002-3 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in proposed IRO-008-1, Requirement R1. That VSL is not binary as is the one proposed for this requirement. It proposes a graduated situation based on a number of days missing from the analysis. In looking at the VSL for this requirement, the SDT decided that it was an all or nothing situation – one either did the proper analysis or it didn't. Therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-002-3 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The proposed requirement is new and there are no comparable VSLs. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-002-3 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental	The proposed requirement is new and there are no comparable VSLs Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

	violations.	those already proposed.			

VSLs for TOP-003-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed IRO-010-1, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the	The proposed requirement is similar to proposed IRP-010-1, Requirement R2. The proposed VSLs both build	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with	The VSL is based on a single violation and not cumulative violations.

	violation and the VSLs follow the guidelines for incremental violations.	on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	violations.	the requirement.	

VSLs for TOP-003-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed IRO-010-1, Requirement R2. The proposed VSLs both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R4:

R#	Compliance with NERC's VSL	Guideline 1	Guideline 2	Guideline 3	Guideline 4

	Guidelines				
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to proposed IRO-010-1, Requirement R3. The proposed VSLs both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1	Guideline 2	Guideline 3	Guideline 4
R5.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to proposed IRO-010-1, Requirement R3. The proposed VSLs both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

Unofficial Comment Form for 4th Draft of Real-Time Operations Standards (Project 2007-03)

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit comments on the 4th draft of the standards for Real-Time Operations (Project 2007-03). Comments must be submitted by **September 3, 2010**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Background Information:
In the 4th posting for Project 2007-03, the Real-Time Operations Standard Drafting Team (RTOSDT) has attempted to clarify the proposed changes to the TOP family of standards based on industry comments received for the 3rd posting.

1. TOP-001-2: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

   ☐ Yes

   ☐ No

   Comments:

2. TOP-002-3: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

   ☐ Yes

   ☐ No

   Comments:

3. TOP-003-1: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

   ☐ Yes

   ☐ No

   Comments:

4. The implementation plan compares the already approved requirements in the "TOP" standards with those that are proposed in TOP-001-2, TOP-002-2, and TOP-003-2. When comparing the already approved standards with those that are proposed, how would you assess the impact to reliability of the proposed standards are approved and the already approved standards are retired in accordance with the implementation plan?

   ☐ Reliability will be improved

   ☐ There will be no change to reliability

   ☐ There will be an adverse impact to reliability

   Comments:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Comment Period Open
August 4–September 3, 2010

Now available at: http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Project 2007-03: Real-time Operations

The Real-time Operations Standard Drafting Team has posted its consideration of comments from the third posting of its proposed modifications to the following standards and associated implementation plan and is seeking comments on the conforming changes made to those documents **until 8 p.m. Eastern on September 3, 2010:**

- TOP-001-2 — Coordination of Transmission Operations
- TOP-002-3 — Operations Planning
- TOP-003-2 — Operational Reliability Data
- Implementation Plan

Instructions

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Courtney Camburn at Courtney.Camburn@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Next Steps

The drafting team will draft and post responses to comments received during this period. The drafting team will also determine whether to post the standard for an additional comment period or seek approval from the Standards Committee to proceed to balloting.

Project Background

The drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The drafting team has added requirements to TOP-001 to address some directives from Order 683 that were not previously addressed in this project.

Applicability of Standards in Project

Transmission Operator
Transmission Owner
Balancing Authority
Generator Owner
Generator Operator
Interchange Authority
Load-Serving Entity
Distribution Provider

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Individual or group. (34 Responses)
Name (20 Responses)
Organization (20 Responses)
Group Name (14 Responses)
Lead Contact (14 Responses)
Question 1 (31 Responses)
Question 1 Comments (34 Responses)
Question 2 (29 Responses)
Question 2 Comments (34 Responses)
Question 3 (31 Responses)
Question 3 Comments (34 Responses)
Question 4 (32 Responses)
Question 4 Comments (34 Responses)

-
Individual
Dan Rochester
Independent Electricity System Operator
Yes
We applaud the SDT of its positive response to our previous comments regarding the lack of monitoring of and requirement to operate within SOLs. Although the revisions do not go all the way to ensuring operating within all SOLs, and mitigating exceedances as they occur, the revised standard goes a long way in meeting that general intent. We agree with all the changes to the Time Horizons, Measures, data retention and compliance elements (VRFs and VSLs).
Yes
Again, we applaud the SDT of its positive response to our previous comments regarding the lack of consideration to SOLs in operational planning. Although the revisions do not go all the way to ensuring TOPs plan their operations to respect all SOLs, the revised standard goes a long way in meeting that general intent. We agree with all the changes to the Time Horizons, Measures, data retention and compliance elements (VRFs and VSLs).
No
M5: The last sentence added is in fact a requirement. Measures should not include requirement for “completeness” of the data provision, which is already implicit in R5. The extent to which the data is not fully provided should be assessed and reflected by the VSLs. Suggest to delete this sentence and as desired, expand the VSLs for R5 to make them graded according to the percentage of data not provided.
There will be no change to reliability
Our assessment that there should be no change to reliability is made on the assumption that the SOLs identified as a result of the Operational Planning Analysis by the Transmission Operator as supporting its local area reliability can ensure that all the existing SOLs that are being monitored and observed (for non-exceedance) by TOPs are identified through this process. Failure to identify any such SOLs will expose the system to unreliable operation.
Individual
Joylyn Faust
Consumers Energy
No
R2 is ambiguous, must a BA inform its TO of an inability to perform a directive after the directive has been issued or at anytime its systems are down and it has temporarily lost its ability to perform some function. R12-14 appear to provide the TO with omnipotent information rights which may include the ability to create monitoring requirements of other entities and control over maintenance schedules of other entities telemetry and associated facilities. Furthermore reciprocal data rights are not provided.
No
The proposed standard which indicates the TO shall “notify” reliability entities as to “their role” appears to be bolstering the authority of the TO. During real time events the TO should have authority to issue directives, however on a planned basis TOs should coordinate, not dictate the role of the entities. On a planned basis, input from the involved entities will result in a more reliable system.
No

Poorly worded. According to the proposed standard the TO is supposed to “exchange” data, at its discretion, regarding equipment ratings at voltage levels below the BES. So when our TO demands HVD equipment ratings, what are we to exchange it with? Again, this standard appears to be bolstering the authority of the TO. If the TO can demand information from the DP, then the DP should have access to similar information regarding the TO’s system.
There will be an adverse impact to reliability
See previous responses.
Individual
John Fish
TransCanada
No
M4. "The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled." Should be removed The response to the "request for data", or an attestation that no requests have been made, should stand alone as proof of GO/GOP compliance??
There will be no change to reliability
Group
Northeast Power Coordinating Council
Guy Zito
Yes
In R9, to clarify the requirement to operate below a System Operating Limit (SOL), “outside” should be replaced with the wording “at or above”.
Yes
Yes
There will be no change to reliability
No change to reliability assumes that the SOLs identified as a result of the Operational Planning Analysis by the Transmission Operator as supporting its local area reliability can ensure that all the existing SOLs that are being monitored and observed (for non-exceedance) by TOPs are identified through this process. Failure to identify any such SOLs will make the system vulnerable to unreliable operation.
Individual
Jonathan Appelbaum
The United Illuminating Copany
No
“Operational Planning Analysis” is not a defined term in the NERC Glossary and a proposed definition is not included in the Draft Standard. TOP-001 and TOP-002 have capitalized the term indicating a definition. TOP-002 information box says “by definition Operational Planning Analysis includes Contingency Analysis.” TOP-001 R12 and R13 were added in this posting to address Order 693 paragraph 1660 and 1661 direction to include the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. The drafting team utilizes the phrase “shall monitor, or shall have access to information about, conditions and Facilities..” By offering an alternative to “monitor” the drafting team is implying there is a difference between “monitor” and “having access to information”. UI suggests retaining “monitor” and removing “access to information about” because the TOP needs the minimum capability of monitoring the Facilities in its area to perform its reliability functions.
Yes
“Operational Planning Analysis” is not a defined term in the NERC Glossary and a proposed definition is not included in the Draft Standard. TOP-001 and TOP-002 have capitalized the term indicating a definition. TOP-002 information box says “by definition Operational Planning Analysis includes Contingency Analysis.”
Yes
There will be no change to reliability

The team has rationalized the existing Standards and Requirements
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
Yes
Yes
There will be no change to reliability
Individual
Jon Kapitz
Xcel Energy
No
R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. Xcel Energy has concerns about the use of the term “affected”. This can be widely interpreted by the entity and compliance enforcement authority. We suggest that language limit the entity’s obligation to Adjacent entities and the Reliability Coordinator. The RC should be held responsible for making this assessment from a regional perspective and make notifications to other entities as it is required to or deems necessary. R13. Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. Xcel Energy has concerns as to whether this requirement indicates that a TOP must have monitoring capability for other TOP areas. This requirement should encompass only a TOP’s own area. R14. Each Transmission Operator shall provide approval rights for planned maintenance of its monitoring and analysis capabilities to its System Operators. Xcel Energy believes this requirement should be worded so that it covers only monitoring capabilities for its own area, and items that it is in control of. (e.g. not feeds from other entities that input into a TOPs own monitoring capability) M11 through M14 list incorrect associated requirements. This appears to be a mapping issue.
No
R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. Xcel Energy believes this requirement is confusing as written. It appears to want to include all SOLs. If so, why not just state as such? It could be simply stated as “…IROLS and SOLS…” R3. Each Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). Xcel Energy believes this should be limited to just entities within the TOP’s own area.
Yes
There will be no change to reliability
Individual
Howard Rulf
We Energies
No
R7: What does it mean to be “outside” an IROL? Vague. R8: Since any SOL is to “ensure operation within acceptable reliability criteria” this requirement requires that the TOP inform the RC of all SOLs. How can the Time Horizon be Real-Time Operations? Operational Planning Analysis is done at least day ahead? R9: What does it mean to be “outside” an SOL? Vague. R10: How do I correlate “within limits” to “inside/outside”?
No
Rationale for Requirement R1: Operational Planning Analysis does not include Contingency analysis “by definition”. “Contingency analysis” does not appear in the definition of Operational Planning Analysis. R2: Since any SOL is to “ensure operation within acceptable reliability criteria” this requirement requires that the TOP include all SOLs in their “plan”. R3: When is this notification to take place? Since this analysis starts taking place as much as 12 months in

advance, as the plan changes over time there could be multiple conflicting notifications.
No
TOP-003-2 R1: Nowhere in NERC Standards is a TOP or BA required to perform an Operational Planning Analysis. This requirement applies to data specifications. It does not require Operational Planning Analysis. R1.2: Who mutually agrees to the format? The TOP and BA? A TOP or BA may have scores of different entities with Facilities within their boundaries. Is this requiring data format agreements with scores of other entities? The TOP and BA should be allowed to specify the data format. R4: Please explain what is meant by "satisfy the obligations of the documented specifications for data". Please rephrase this to something more clearly understandable in the requirement. R5: Consider modifying this requirement so that the data is provided directly where possible. Data received indirectly through other entities is delayed, and there are increased chances of problems in receiving the data.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
In R3 the language should be "...be affected by actual..." and not "...be affected of actual..." Measures M10-M14 are off by 1 in pointing back to their respective requirements (i.e. M10 is pointing back to R9, etc). It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
No
In "Consideration of Comments on First Draft of Revised TOP Standards Real-Time Operations - Project 2007-03," p77, #6 response, March 26, 2009, it was stated that "reliability entities" is not a defined term. In addition, in "Consideration of Comments on Second Draft of Standards for Real-Time Operations (Project 2007-03)," pp 64-65, August 25, 2009, a response is given to Xcel Energy's comment that the phrase reliability entities needs definition that "reliability entities are the entities certified by NERC as such." SCE&G believes that it is unclear what is meant by "certified by NERC as such" and would appreciate that these entities be spelled out as it relates to these Standards. It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
No
It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Reliability will be improved
It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Individual
Greg Rowland
Duke Energy
No
• What does the drafting team mean by "its inability" in R2 to perform a Reliability Directive? There clearly needs to be a distinct difference between the reasons in R1 and "inability" in R2. Duke wants to eliminate the possibility of double jeopardy for an entity to be assessed a possible violation for non-compliance to one action with it stated similarly in two requirements. • R3 typo – change the word "of" to "by". • R8 – the phrase "supporting its local area reliability" is unclear. Replace it with the phrase "having an Adverse Reliability Impact". This adds clarity and also recognizes that local area problems that don't rise to the level of Adverse Reliability Impact should not be treated as SOLs required to be reported to the RC under this standard. • R9 – insert the phrase "as having an Adverse Reliability Impact" after the phrase "Requirement R8", making R9 consistent with R8. • R13 – strike the phrase "shall monitor, or". The TOP doesn't need to directly monitor facilities in other TOP areas. • M1 – strike the word "either" and replace the phrase "or, (b) informed the Transmission Operator that" with the word "unless". This makes M1 consistent with the R1 revision above. • M3 typo – replace the word "of" with the word "by". • M5 typo – the word "operations" appears twice. Need to strike the first one. • M8 – replace the phrase "supporting its local area reliability" with the phrase "having an Adverse Reliability Impact", consistent with the R8 revision above. • M13 – strike the phrase "can monitor, or" consistent with the R13 revision above. • R1 VSL – replace the phrase "and the respective entity did not inform the Transmission Operator that such action would" with the phrase "and compliance with the Reliability Directive would not", consistent with the R1 revision above. • VSLs for R3, R5, R6 and R8 – The mixing of numbers with percentages and the phrase "whichever is less" in these VSLs is confusing. For example, if under R5 there are four affected entities, and the TOP does not coordinate operations with one of the four, then that is one

entity, or 25% of the total. What does “whichever is less” mean? Is that a Lower or Severe violation? Conversely, if there is only one affected entity and the TOP does not coordinate operations with that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation? • R8 VSLs – In each VSL, replace the phrase “supporting its local area reliability” with the phrase “having an Adverse Reliability Impact, consistent with the R8 revision above. • R13 VSL – Strike the phrase “monitor, or”, consistent with the R13 revision above.
No
• R2, M2 and R2 VSL – Replace the phrase “supporting its local area reliability” with the phrase “having an Adverse Reliability Impact”. This adds clarity regarding which SOLs must be addressed in the TOP’s plan. • R3 VSL - The mixing of numbers with percentages and the phrase “whichever is less” in these VSLs is confusing. For example, if there are four affected entities, and the TOP does not notify one of the four, then that is one entity, or 25% of the total. What does “whichever is less” mean? Is that a Lower or Severe violation? Conversely, if there is only one affected entity and the TOP does not notify that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation?
No
• R2 and R3 VSLs - The mixing of numbers with percentages and the phrase “whichever is less” in these VSLs is confusing. For example, if there are four entities, and the TOP or BA does not distribute its data specification to one of the four, then that is one entity, or 25% of the total. What does “whichever is less” mean? Is that a Lower or Severe violation? Conversely, if there is only one entity and the TOP does not notify that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation?
There will be no change to reliability
These revised standards (including our proposed changes), provide more clarity and will improve compliance documentation, but we don’t view that as a reliability improvement. Redline Posting for TOP-001-2 has a slight different definition than the Implementation Plan for Project 2007-03: Real-Time Operations Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency. Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency. Duke prefers the first definition. It is the one based on the definition of “Emergency” since it doesn’t mention “actual or expected”.
Group
Public Service Enterprise Group Companies
Kenneth D. Brown
No
In R1 the word "identified" was added as an adjective to describe "Reliability Directive." While this is a step in the right direction, it needs further clarification. The requirement should be further modified to indicate that the Transmission Operator must indentify. i.e., state that "this is Reliability Directive" to ensure that the entities that must comply with this requirement know that what is being communicated by the TOP is a Reliability Directive and not some other less urgent communication.
No
The Rational to R1 should add language to clarify that in some circumstances the failure or unavailability of the usual tools may result in the inability to perform a complete and comprehensive analysis. Therefore the words "to the extent practicable" should be added (see below) in the last sentence after the word "able." Rationale for Requirement R1: By definition, Operational Planning Analysis includes Contingency analysis. By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have analysis tools or procedures to perform the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, if tools are used, the Transmission Operator must be able to the extent practicable to complete the analysis even if those tools are not available.
Yes
Reliability will be improved
Group
E.ON U.S.
Brent.Ingebrigtson@eon-us.com
No
E.ON U.S. suggests that in the definition of directive the adjective “mandated” should be added and placed in front of “action.”

Yes
Yes
There will be no change to reliability
Group
Midwest ISO Standards Collaborators
Marie Knox
No
Requirement #1 Comments can not be developed for this requirement until we are able to see a final draft of the definition of Reliability Directive. It will have a significant impact on this requirement. Requirement #9 SOL's have not been defined clearly enough to require an identified time limit for exceedance. These durations could be set by the Transmission Owners or Operators based on the type of equipment, not dictated in the standard. Requirement #10 It is not clear when the RC should be informed, before, during or after actions have been taken to correct an overload. This needs to be discussed. Depending on the urgency of the situation, it may not be appropriate for the TOP to inform the RC prior to taking actions. It should simply be a requirement for the TOP to log or record actions taken for future review. Requirement #13 It is not clear what TOP area needs to be monitored. Language needs to be added to clearly state that a TOP should have access to information on other TOP areas that could impact the local area.
Yes
Yes
There will be no change to reliability
Individual
Michael Lombardi
Northeast Utilities
No
Both Requirements R12 and R13 are considered vague and open to interpretation. For example, what type of information is to be monitored and what is meant by conditions? Language needs to be added to clearly state what a TOP needs to accomplish pursuant with these requirements. Various Measures appear to have incorrect Requirement references. For example, the text of Measure M14 refers to Requirement R13. Please verify / correct the Requirement references for all Measures. The term "Operational Planning Analysis", is capitalized to identify it as a defined term yet the NERC Glossary of Terms (updated 4/20/2010) indicates that the term has not been FERC approved. NU is concerned that the terms Operational Planning and Operational Planning Analysis are not FERC approved and may not be consistently applied throughout the industry. Suggest these terms be reviewed as part of this standard to ensure industry consensus on these terms and subsequently seek FERC approval, as required.
No
The rationale box for Requirement R1, indicates that TOP must be able to complete analysis even if the tools that are used are not available. It is not clear how contingency analysis would be performed if study tools are not available. What if day ahead study tools are part of an Energy Management System (EMS) which is a high reliability redundant system with an independent system at a back up facility? Is the rational box verbiage suggesting one would need to postulate the loss of a redundant EMS as well as its back up facility? Please clarify what is to be accomplished pursuant with R1. The term "Operational Planning Analysis", is capitalized to identify it as a defined term yet the NERC Glossary of Terms (updated 4/20/2010) indicates that the term has not been FERC approved. (See additional write up in Question 1 comment)
Yes
Reliability will be improved
Group
Bonneville Power Administration
Denise Koehn
No

R5 - should refer to adjacent Transmission Operators. R8 - This daily documentation is burdensome. Reporting “all” SOL's to RC ahead of time as part of daily assessment in addition to the daily planned outage heads-up reporting. Suggest clarifying SOL as intended to be path loading limits and/or local area transmission service support limits, (the BES is a big system with lots of ratings, it can also mean voltage limits in addition to line and path limits). If there is a significant change to a limit, that would be important. R10 – Prefer having the RC call the TOP in 5 Minutes to ensure entity is aware of and acting on a limit excursion , rather than TOP interrupt system response to call RC to tell them the Operator is mitigating a SOL violation which is a already a NERC TOP standard to take immediate action. There's a typo in M12, M13, M14 when it refers to the wrong requirement due to renumbering R11 instead of R12, R12 vs R13, R13 vs R14).
No
R2 Although an entity does not plan to operate above the SOL, a contingency may cause an short SOL excursion until planned mitigation action is completed within the Tv (allowable violation time limit). Non-electrical people could get confused by this distinction. Suggest clarifying SOL as intended to be path loading limits and/or local area transmission service support limits, (the BES is a big system with lots of ratings, it can also mean voltage limits in addition to line and path limits).
Yes
There will be no change to reliability
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Reliability will be improved
The proposed standards will improve reliability because the new standards provide a much more clear and streamlined approach than in the already approved standards. This will also enable responsible entities to focus their time on compliance with standards that improve reliability rather than be concerned with compliance with poorly written or redundant standards.
Group
SERC OC Standards Review Group
Mike Hardy
No
In R2, it appears that an entity might be faced with double jeopardy if it fails to notify the entity issuing the directive. Doesn’t R1 also include this same requirement? In R3, the phrase “affected of actual’ should be “affected by actual”. In R8 and M8, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”. In R12 and R13, it doesn’t seem possible to measure “monitoring”. These also seem like requirements that are ideally suited for the certification process. It appears that the numbering of the requirements within each measure may have gotten out of synch due to a cut and paste insert. In M8, SOLs should be singular. The data retention periods are too long and do not appear to serve the purpose of improving reliability. Specifically, the three (3) year retention period for SOL and IROL violations is two (2) years too long.
No
In R2 and M2, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”.
No
We believe that R5 is redundant to R4 if the Transmission Operator is added to R4.
Reliability will be improved
“The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its

board or its officers.”
Individual
Leland McMillan
NorthWestern Energy
Yes
NorthWestern Energy appreciates this chance to comment. NorthWestern supports the definition of "Reliability Directive" as indicated in the Definitions section. R13 could be clarified to specify the exact types of information about conditions and facilities identified that the entity must have access to. Also, NorthWestern seeks clarification as to why the requirement mandates that the TOP shall have this information "within any Transmission Operator Area"? Perhaps the intent of the requirement is geared towards TOPs obtaining operating information pertaining to their own TOP area, regardless of which TOP area it is actually physically located in? NorthWestern requests that the drafting team consider flexibility in the implementation timelines of this standard. Compliance with this standard might require Transmission Operators to acquire/arrange for Operational Analysis and planning simulation tools not currently required by any FERC approved standards.
Yes
Yes
Reliability will be improved
Group
Southern Company Transmission
JT Wood
No
Southern's comments: Suggest modifying R3 language for additional clarity. Suggested alternatives might be “Each Transmission Operator shall inform its Reliability Coordinator of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis, and shall likewise inform any other Transmission Operators that are known or expected to be affected by those Emergencies” or “Each Transmission Operator shall inform its Reliability Coordinator and all other expectedly affected Transmission Operators of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.” In the first sentence of M5, the first usage of the word “operations” is redundant and can be struck. In R8, it is unclear what should be the treatment of SOLs that develop due to unanticipated system conditions that are not included in the Operation Planning analysis (i.e., real time system conditions deteriorate due to several unplanned outages). In R11, need to add “…within 30 minutes” after SOL. R14 can be mis-read to mean that the Transmission Operator grants approvals of outages, as opposed to granting the authority to grant approval to the System Operator. Also, it would be useful to clarify if the TOp still has the authority to also veto planned outages, in addition to the System Operator having that authority. M11 – M14 have references to incorrect Requirement numbers. In M8 and M14, the word “its” was incorrectly modified to “it’s.” SERC's comments: Southern participated in developing these comments and support them In R2, it appears that an entity might be faced with double jeopardy if it fails to notify the entity issuing the directive. Doesn’t R1 also include this same requirement? In R3, the phrase “affected of actual’ should be “affected by actual”. In R8 and M8, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”. In R12 and R13, it doesn’t seem possible to measure “monitoring”. These also seem like requirements that are ideally suited for the certification process. It appears that the numbering of the requirements within each measure may have gotten out of synch due to a cut and paste insert. In M8, SOLs should be singular. The data retention periods are too long and do not appear to serve the purpose of improving reliability. Specifically, the three (3) year retention period for SOL and IROL violations is two (2) years too long.
No
Southern's comments: The current NERC Glossary definition of Operations Planning Analysis does not explicitly include contingency analysis. Unless the SDT is modifying the definition of Operations Planning Analysis to include contingency analysis, we recommend that R1 be re-expanded to include the expectation of performing contingency analysis. Regarding R2 and M2, a TOp should not plan to operate beyond any SOL limit – regular or one that “is supporting local reliability.” Otherwise, why should it be classified as an SOL? SERC's comments: Southern participated in developing these comments and support them In R2 and M2, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”.
No

Southern's comments: M4 and M5, there should be allowance for outstanding requests that are still within the deadline as defined in R1.4. SERC's comments: Southern participated in developing these comments and support them We believe that R5 is redundant to R4 if the Transmission Operator is added to R4.
Reliability will be improved
Southern's comments none SERC's comments: Southern participated in developing these comments and support them Although we feel that reliability will be improved, we cannot determine whether the language that was inserted specifically in response to order 693 is not arbitrary, capricious or otherwise deleterious to reliability.
Group
FirstEnergy
Sam Ciccone
No
We agree with many of the changes the drafting team made to this standard. However, we have the following comments and suggestions: a. With respect to R7 and R11 in relationship to IROLs, R11 is inherent in R7. If an entity is not permitted to operate outside an IROL limit for longer than its Tv, then it needs to implement whatever actions are required to comply with Tv including directing "others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv." R9 and R11 have the same issue with respect to SOL's. M3 is silent on evidence related to the Operational Planning Analysis. Did the drafting team intend for this data to be available for inspection as a means of proving or disproving the affect on a Neighboring Transmission Operator and thereby the need to contact them? If it is the intent of the drafting team to use the Operational Planning Analysis as evidence, then it should be specifically stated in M3. If it is the intent of the drafting team for an entity to be able to prove "conditions did not permit such coordination" then that evidence should be specified in the measures. b. R11 – We believe that requiring the TOP to mitigate IROLs is outside their scope per the functional model. The RC holds the authority over the tools needed to mitigate an IROL and is the appropriate entity responsible for this requirement. Also, it seems as though this requirement is duplicative of IRO-009-1 R4 which states "When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. (Violation Risk Factor: High) (Time Horizon: Realtime Operations)". c. R13 – We suggest the team remove the phrase "within any Transmission Operator Area" from the requirement. We believe this phrase is not necessary and adds confusion. d. R14 – The original SAR charged with addressing Order 693 directive 1660 required the standards to identify the minimum monitoring and analysis capabilities. The new requirement R14 does not fully address these minimum capabilities and will leave the requirement ambiguous from a compliance and enforcement standpoint. We suggest the team fully address the directive and clarify the requirement. e. Measures M10 through M14 make reference to the wrong requirements.
Yes
Yes
We commend the drafting team for attempting to manage the evidence in a way that does not require the TOP to get evidence to prove an absence of an issue, however, the following statement needs clarification to remove the double negative verbiage, "The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled." This statement might be improved by stating "The evidence shall be the Transmission Operators and Balancing Authorities requests have been met." This will allow the entity to show the requests received from other entities and the evidence that they filled those requests.
There will be no change to reliability
We commend the hard work of the drafting team, but find it difficult to determine if these changes will affect the reliability of the BES.
Individual
Richard Kafka
Pepco Holdings, Inc.
No
R6 requires coordination which leads to questions regard who is non-compliant. It would be more proper to require reporting and approval requirements. RCs already are required to coordinate with each other. R9 sets a 30 minute limit on all identified SOLs (as opposed to allowing different times). This would require all facilities to have the same time limits for ratings. That should be addressed in FAC-008.
Yes
Yes

Reliability will be improved
Group
Dominion
Louis Slade, Jr.
No
Agree with changes to most requirements and measures, but with exceptions as noted below: R2 – Is covered in R1. Do not agree with entity being subject to non-compliance for same shortcoming under 2 requirements. We suggest R2 be removed or that R1 and R2 be revised so that the requirement to inform the TOP not be included in both. R13 – Is the sentence meant imply that a TOP should monitor or have access to information/facilities in another TOP Area that could impact its TOP Area? If so, we believe the current draft language should be revised to improve clarity of intent. We suggest revising to read “Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within external Transmission Operator Area(s) as necessary to perform such analysis” M1/M2 – revise measures so that entity is not subject to non-compliance for failure to notify TOP twice, pursuant to changes in R1/R2. M8 – change SOLs to SOL. M13 – revise pursuant to R13.
Yes
No
It is not clear how the data provision obligations of BAs under requirement R4 are different from their obligations under R5. We therefore suggest that TOP be added to R4 and that R5 be removed.
Reliability will be improved
While the changes remove potential ambiguity from the reliability requirements, we believe that BAs, TOPs and RCs, in almost all circumstances, understand the roles they play to insure reliable grid operations. We believe these changes are predominately the result of an increased focus on compliance related activities (audit) and industry requests for clarity. We do agree that the change in R8 is an improvement as it will allow TOP and RC to focus on the limited set of SOLs that could have an adverse impcat on the BES. Dominion would also like to make a general statement concerning the VSLs for all of these standards. We are unsure as to whether the correct threshold for Low, Moderate, High and Severe is correctly identified but have no basis for a denial or suggested change. We are curious as to how the various SDTs came up with these. In some draft standards, these thresholds seem to be developed around 25% quartiles, which makes it easier to accept the high and severe categories if you consider these equivalent to a pass/fail (D or F).
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
No
The proposed TOP-001-2 standard is a significant improvement, but there are still important items that need to be addressed including: Comments cannot be developed for this requirement until a final draft of the definition of Reliability Directive is presented as it will have a significant impact on TOP-001-2 and R1. When Reliability directive is defined, the definition of a Reliability Directive is too broad and should be limited to “Abnormal conditions that require operational actions to avoid instability, uncontrolled separation and cascading as defined in Section 215 of the Federal Power Act.” TOP-001-2-R9: SOL’s should not be part of the TOP-001-2 standard as there are not identified timeframes in the NERC standards today. However, if SOL’s must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded such as 30 minutes after exceeding the specified SOL limit. An example definition might be non-thermal SOL’s are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability. TOP-001-2-R10: It isn’t clear when the RC should be informed, before, during, or after actions have been taken to correct an overload. Depending upon the urgency of the situation, it might not be important to notify the RC, therefore the requirement should be changed to the TOP should record actions taken for future review. For TOP-001-2-R6 replace “coordinate” with “notify the RC and negatively impacted adjacent interconnected NERC registered entities of” For TOP-001-2-R3, the words “and anticipated” needs to be dropped as an unmeasurable requirement. In TOP-001-2-R2 and R4, “expected to be affected” would include known. We asked the SDT to please strike known. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for TOP-001-2-R5 and R8 need to be clear that these are event driven requirements and evidence is only required if an “event” has occurred. In R6, the word “telemetering” should be

capitalized as it is a defined term in the NERC Glossary. The terms “control equipment” and “associated communications channels” are not defined in the glossary at all. Recommend modifying the wording to ensure consistency between standards. R14 uses the term “monitoring and analysis capabilities”. This term is not defined in the NERC Glossary. R13 implies that a TO’s Operational Planning Analyses should be monitoring facilities external to its own operating area when they have no control or responsibility for said facilities. It is not a TO’s responsibility to monitor regional system conditions; therefore this requirement should be removed. FERC Order 693, paragraphs 1660 and 1661 do not specifically mention any of the verbiage in requirements R12, R13, & R14; therefore the preceding statement should be considered.
No
The rationale box needs to be clarified. If the drafting team meant for entities to have a primary set of tools / procedures and backup set as well, please clarify that. “By definition, Operation Planning Analysis includes Contingency analysis” is not accurate. The definition in the Glossary of Terms mentions nothing of contingency analysis. It mentions known transmission and generation facility outages, but that has nothing to do with contingency analysis, which includes a study of unknown events to occur on current system conditions. Therefore, the requirement should read “Each Transmission Operator shall have an Operational Planning Analysis that incorporates potential single contingency events.” Is “plan” in requirement R2 a noun or verb? It appears to read as if it is a verb, which implies no documented action would be necessary. If intended, it should read “Each Transmission Operator shall develop a plan….” This flows much better with what the intent of R2 is trying to say.
No
Remove “at the discretion of the Transmission Operator or Balancing Authority” in R1-1.1. The TO and BA are the entities creating the specification, which already implies that any needed parameters are at their discretion. Overall clarification seems necessary on this bullet as well (R1-1.1). Why specifically address equipment of voltage levels below BES levels? Does this exclude equipment rated 100 kV and above? Replace “Real-time monitoring” with “Real-time Assessment” as this is an actual term in the NERC Glossary of Terms. This would follow a similar format to the “Operational Planning Analyses”.
There will be no change to reliability
There seems to be a general lack of consistency in the use and meaning of terms relating to remote measurement and remote control of the BES in the TOP, COM and PRC standards. A better glossary would ensure consistent verbiage between the standards groups. The glossary term “Telemetering” is confusingly similar to the one for “SCADA”. It wrongfully includes remote control as part of the definition. We suggest it be removed from the glossary and this project.
Individual
Saurabh Saksena
National Grid
No
R13 states that - Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. What does “Facilities” in R13 refer to? Is it any facilities that are included in the analysis or those that have the potential to cause violations? Suggest replacing “..Facilities identified in its Operational Planning Analysis” by text in R8 – “…identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis.” TOP-001 R13 also says "...within any Transmission Operator Area...", Does the drafting team mean within that particular TOP's area? It would be more clear if it said "...within its area...". If they really do mean another TOP's area, that is unrealistic. It could imply that we need to have info for TOP in Florida. TOP-001 R8 & TOP-002 R2 - When referencing SOLs both say something like "SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability...". National Grid suggests deleting “…which, while not IROLs…”.
No, No
TOP-001 R8 & TOP-002 R2 - When referencing SOLs both say something like "SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability...". National Grid suggests deleting “…which, while not IROLs…”.
TOP-001 R8 & TOP-002 R2 - When referencing SOLs both say something like "SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability...". National Grid suggests deleting “…which, while not IROLs…”.
Yes
There will be no change to reliability

Group
PJM
Patrick Brown
No
There are several issues with Requirement 6: • The requirement assigns responsibility to 3 entities for one task. NERC standards are designed to clearly assign responsibility to provide a clear measurement and allocation of non-compliance. R 6 as worded requires “coordination” between and among each entity. • Coordination is not defined. Does coordination mean “informing” another party? Does it mean “directing a new solution”? Does it mean “asking permission” of a third party? • Who is non-compliant when two (or more) parties do not agree with a proposed solution? How many alternatives proposals must be considered? Suggest the requirement be rewritten as a series of independent requirements with sub-bullets to identify specific tasks. Example: Each TOP shall inform all affected reliabity entities of planned outages of active real-time communications channels: • Interpersonal channels • Data exchange channels for any BES elements or elements involved in identified IROL computations • Asset direct-control devices (reactive control equipment,…) Each TOP shall inform all affected parties of alternative means to be used for the duration of the proposed outage. Each BA shall inform all affected reliability entities of planned outages of active real-time communications channels: • Interpersonal channels • Data exchange channels for any BES elements or elements involved in identified IROL computations • Asset direct-control devices (regulation control signals; resource dispatch equipment,…) Each GOP shall inform all affected reliability entities of planned outages of active real-time communications channels: • Interpersonal channels • Data exchange channels for any BES elements or elements involved in identified IROL computations • Asset direct-control devices Each reliability entity inform by the TOP in Rx.x, (or by the BA in Ry.y or by the GOP in Rz.z) shall acknowledge the receipt of the information provided in Rx.x (or in Ry.y or Rz.z) to the respective TOP (BA or GOP). Requirement #13 Delete the phrase “…within ANY Transmission Operator Area”. The phrase has the potential to add confusion rather than clarity to the requirement.
There will be no change to reliability
Individual
Randi Woodward
Minnesota Power
Minnesota Power does not have any comments at this time.
Minnesota Power does not have any comments at this time.
No
Minnesota Power has the following comments for the individual requirements of the proposed Standard TOP-003-2. Requirement 1 • The time horizon doesn’t appear to match the requirement. • The tasks required to accomplish the items listed in sub-requirements R1.1 – R1.4 also fall under the responsibility of a Reliability Coordinator, in addition to the Transmission Operator and Balancing Authority functions that are already listed in this Requirement. • The term “mutually agreeable format” is confusing and needs more definition to eliminate any confusion regarding who is required to agree on the format in sub-requirement 1.2. Requirement 4 • The way this Requirement is currently worded could leave the door open for disparate specifications. As currently written, Registered Entities are obligated to abide by all specifications regardless of feasibility or ability to implement. Minnesota Power requests more clarification regarding what is meant by “satisfy the obligations of the documented specifications for data.” Requirement 5 • The way this Requirement is currently written it could open the door for a liberal interpretation of the Requirement and could result in excessive data requests in the name of “Operational Planning Analysis and Real-time monitoring.” Minnesota Power suggests revising the Requirement to state that the requesting Transmission Operator and/or Balancing Authority must demonstrate a reliability need in its request for data.
Minnesota Power does not have any comments at this time.
Group
IRC Standards Review Committee
Ben Li
No
Requirement #1 Comments can not be developed for this requirement until we are able to see a final draft of the definition of Reliability Directive. It will have a significant impact on this requirement. Requirement #9 A 30-minute time limit has been identified in Requirement 9, but that may be an inappropriate time based upon the variability that exists with actual system operating limits. In the case of thermal limits, some may be 15 minutes others may be 4 hours for different facilities. The same facility may have a 4 hour loading limit, and a 2 hour limit at a higher magnitude, as well as, perhaps, a 30 minute limit at a higher magnitude yet. If the limits were allowed to only be set

at 30 minutes, how are longer limits incorporated? Of course it is imprudent to operate a facility at the magnitude corresponding to a four hour limit for greater than four hours. But how is that limit identified and communicated if the System Operating Limit must be mitigated within 30 minutes? Any such operating parameter will be recognized as an SOL, then requiring a 30 minute limit if Requirement 9 is left as is. Requirement 8 mandates that limits be set to support local area reliability. Operating a facility for five hours at its four hour limit is contrary to that requirement. Transmission Operators need SOLs to be described and communicated in terms of both magnitude and associated time, but that time need not be limited to 30 minutes. The duration and magnitude of the SOL should be set by the Transmission Owners or Operators based upon respecting the facility and equipment ratings as required by the FAC standards. Requirement 9 would better serve reliability to require SOLs (which are identified in Requirement 8) to be described in specific terms of both magnitude and associated time. If needed, a fallback position could be maintained that establishes 30 minutes as the default time limit if no other limit is specifically defined in the SOL. Requirement #13 It is not clear what TOP area needs to be monitored. Language needs to be added to clearly state that a TOP should have access to information on other TOP areas that could impact his local area.
Yes
No comment at this time. (The YES box was inadvertently checked, which we are unable to de-select)
Yes
No comment at this time. (The YES box was inadvertently checked, which we are unable to de-select)
There will be no change to reliability
Individual
Darryl Curtis
Oncor Electric Delivery
Yes
Reliability will be improved
Individual
Catherine Koch
Puget Sound Energy
No
R1 – The addition of the term “identified” does not completely answer the question of who needs to identify the communication as a Reliability Directive. Simply adding the term means that it might be interpreted to mean that that the entity receiving a communication from a Transmission Operator might need to identify the communication as a Reliability Directive from its content and context. The following formulation is more clear: “Each Balancing Authority … shall comply with each Reliability Directive that its Transmission Operator issues and identifies as a Reliability Directive, …” Given the importance of these requirements, clarity must not be sacrificed for brevity. R8 – The use of the phrase “have been identified” is unnecessary in this requirement. The Transmission Operator has an independent obligation to identify these SOLs under the FAC standards. In addition, the phrase “its local area reliability” is ambiguous. If the intent of this term is to address a certain set of SOLs that have more than a purely local effect, then the phrase should be modified to something like “regional reliability” or “that may affect its neighboring Transmission Operator Areas”. The requirement should read “Each Transmission Operator shall inform its Reliability Coordinator of all SOLs that, while not IROLs, support regional reliability based on its assessment of its Operational Planning Analysis” or “Each Transmission Operator shall inform its Reliability Coordinator of all SOLs that, while not IROLs, that may affect its neighboring Transmission Operator Areas based on its assessment of its Operational Planning Analysis.” M1 – To be consistent with the recommended revisions to R1, the measurement should be revised to read “Each Balancing Authority … (a) complied with each Reliability Directive that its Transmission Operator issued and identified as a Reliability Directive, …". Additionally we suggest that the measures provide guidance of how to prove a Reliability Directive was not issued in order to be complete in demonstrating compliance with the requirment. This same suggestion rings through all the measures. M2 – This measurement duplicates a portion of M1.
No
R1/R2 – The side-bar indicates that Contingency analysis is included Operational Planning Analysis by definition. The definition of Operational Planning Analysis, however, does not discuss or even mention Contingency analysis. Recommend a revision to the definition of Operational Planning Analysis to clarify that such an analysis does include Contingency analysis. R2 – See comments regarding identified SOLs under requirement R8 of TOP-001-2 above.

No
R1 – As indicated in the first full row on page 5 of the document "Resolution of Issues Assigned to Real-time Operations SDT (Project 2007-03)", FERC staff disagrees with the data specification approach. How does the SDT propose to deal with this disagreement? Given this disagreement and FERC's current concerns with NERC's standard approval process, what purpose does continuation of the current approach accomplish? R1.2 – The phrase "mutually agreeable format" may lead to disputes between the TOP and other entities subject to the TOP's data specification. In the event that the entities cannot agree, the TOP's reasonable requirements should trump. R1.4 - There should be language added that requires agreement to proposed deadline by the entity receiving the specification as there could be a need for programming work and it could be foreseen that the deadline indicated can not be reasonably met.
There will be no change to reliability
Individual
Terry Harbour
MidAmerican Energy
No
The proposed TOP-001-2 standard is a significant improvement, but there are still important items that need to be addressed including: Comments cannot be developed for this requirement until a final draft of the definition of Reliability Directive is presented as it will have a significant impact on TOP-001-2 and R1. When Reliability directive is defined, the definition of a Reliability Directive is too broad and should be limited to "Abnormal conditions that require operational actions to avoid instability, uncontrolled separation and cascading as defined in Section 215 of the Federal Power Act." TOP-001-2-R9: SOL's should not be part of the TOP-001-2 standard as there are not identified timeframes in the NERC standards today. However, if SOL's must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded such as 30 minutes after exceeding the specified SOL limit. An example definition might be non-thermal SOL's are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability. Many times scheduled transmission outages coupled with weather (drought, wind front, heat wave, etc) and strong market moves can drive unexpected SOL exceedances where units and markets cannot move within 30 minutes to redispatch sufficient generation. Coupling SOLs with time frames and penalties will drive unforseen market impacts. TOP-001-2-R10: It isn't clear when the RC should be informed, before, during, or after actions have been taken to correct an overload. Depending upon the urgency of the situation, it might not be important to notify the RC, therefore the requirement should be changed to the TOP should record actions taken for future review. For TOP-001-2-R6 replace "coordinate" with "notify the RC and negatively impacted adjacent interconnected NERC registered entities of" For TOP-001-2-R3, the words "and anticipated" needs to be dropped as an unmeasurable requirement. In TOP-001-2-R2 and R4, "expected to be affected" would include known. We asked the SDT to please strike known. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for TOP-001-2-R5 and R8 need to be clear that these are event driven requirements and evidence is only required if an "event" has occurred. In R6, the word "telemetering" should be capitalized as it is a defined term in the NERC Glossary. The terms "control equipment" and "associated communications channels" are not defined in the glossary at all. Recommend modifying the wording to ensure consistency between standards. R14 uses the term "monitoring and analysis capabilities". This term is not defined in the NERC Glossary. R13 implies that a TO's Operational Planning Analyses should be monitoring facilities external to its own operating area when they have no control or responsibility for said facilities. It is not a TO's responsibility to monitor regional system conditions; therefore this requirement should be removed. FERC Order 693, paragraphs 1660 and 1661 do not specifically mention any of the verbiage in requirements R12, R13, & R14; therefore the preceding statement should be considered.
No
The rationale box needs to be clarified. If the drafting team meant for entities to have a primary set of tools / procedures and backup set as well, please clarify that. "By definition, Operation Planning Analysis includes Contingency analysis" is not accurate. The definition in the Glossary of Terms mentions nothing of contingency analysis. It mentions known transmission and generation facility outages, but that has nothing to do with contingency analysis, which includes a study of unknown events to occur on current system conditions. Therefore, the requirement should read "Each Transmission Operator shall have an Operational Planning Analysis that incorporates potential single contingency events." Is "plan" in requirement R2 a noun or verb? It appears to read as if it is a verb, which implies no documented action would be necessary. If intended, it should read "Each Transmission Operator shall develop a plan…."
No
Remove "at the discretion of the Transmission Operator or Balancing Authority" in R1-1.1. The TO and BA are the

entities creating the specification, which already implies that any needed parameters are at their discretion. Overall clarification seems necessary on this bullet as well (R1-1.1). Why specifically address equipment of voltage levels below BES levels? Does this exclude equipment rated 100 kV and above? Replace “Real-time monitoring” with “Real-time Assessment” as this is an actual term in the NERC Glossary of Terms. This would follow a similar format to the “Operational Planning Analyses”.
There will be no change to reliability
Depending upon how SOLs are implemented and enforced there could be a negative impact to system reliability as transmission outages are further restricted reducing long-term maintenance to maximize short term risks to penalties.
Individual
Jason Shaver
American Transmission Company
No
Requirements #1 & 2 ATC supports Requirements 1 and 2 if the definition of Reliability Directive, as provided in TOP-001-2, is not modified. Any change to the proposed definition of Reliability Directive will require us to reevaluate our position. Requirement #3 Issue 1: ATC is concerned with the wording of Requirement 3 because it blends real time Emergencies situations with issues or concerns that are identified in Operational Planning Analysis for next day, week, month or year. Definitions: “Emergency” and “Operational Planning Analysis”: Emergency: “Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the BES” Operational Planning Analysis: “An analysis of the expected system condition for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generation outages, equipment limitations, etc.).” If an Emergency by definition requires automatic or immediate manual action then there would be few if ever a situation in which a next day study would require either automatic or immediate manual action. What reliability objective is the SDT attempting to achieve when combining these two distinct situations into one requirement? Because of this observation ATC believes that the language about anticipated Emergency and Operational Planning Analysis should be deleted. If the SDT does not believe that these deletions are necessary then we request that the SDT provide additional clarify for the phrase “anticipated Emergency”. Supporting TOP Standard: TOP-002-3 addresses the need for a TOP to perform an Operational Planning Analysis and when appropriate to develop a plan based on those results. That plan must be communication to Registered Entities that have to perform an action. (See ATC’s Comments to TOP-002) Because TOP addresses next day studies we believe that there is no need for this requirement to also cover Operational Planning Analysis. Clarifying questions: Does the Operational Planning Analysis have to be performed by the TOP itself? (Situation: Currently MISO does a next day study for its footprint. Could that qualify as an Operations Planning Analysis being performed, or does each TOP have to perform its own next day study.) Requirement 3: “… based on its assessment of its Operational Planning Analysis.” Issue 2: When is notification required to take place? ATC believes that the primary responsibility of the system operator is to address the actual (real-time) Emergency and then when appropriate follow up with the RC and other TOP’s. The only exception is when the TOP has to issue a Reliability Directive which would be issued in response to the situation. Requirement 5: ATC believes that the second sentence should be deleted because all it is attempting to do is provide examples. The first sentence provides enough clarity, so that the second sentence is not needed and may result in more confusion. Requirement 6: Issue 1: Who qualifies as an “affected entity”? If the entity is not registered with NERC how can NERC verify that coordination took place? Does this mean that a TOP, BA and GOP would have to contact customers if the planned outage could affect them? How affected does an entity have to be in order to trigger coordination? Measure 6 states that the TOP, BA and GOP must coordinated “among impacted reliability entities” but there does not exist a definition of “reliability entities”. This standard should clearly set the expectations as to who does the TOP, BA and GOP have to coordinate with and not make the requirement so broad to allow questions about who was involved in the coordination. Issue 2: It is not clear as to when a planned outage of telemetering and control equipment and associated communication channels has to be coordinated. Requirement 7: ATC believes that the term “outside” is not clear and that the SDT should either define the term or use a more appropriate term. Suggested Modification: Modification to R7: “Each TOP shall not “exceed” an identified IROL…” Requirement 8: ATC raised a question on Requirement 3 asking if each TOP has to perform its own Operations Planning Analysis. Based on the answer to that question this requirement may need to be deleted. If an Operations Planning Analysis can be performed by the RC then there would be no need for the TOP to contact the RC about the results of their own study. We believe that Requirement 2 of TOP-002-3 covers Operational Planning Analysis so there is no need to have a duplicate requirement. ATC is unclear as to what this requirement is attempting to achieve. Is this requirement simply saying that the TOP has to share their system operating limits with the RC? If that is the case we believe that the requirement should be rewritten to provide that specific clarity. Suggested Modification: The TOP shall inform the RC of all BES System Operating Limits (SOLs) that support local area reliability. Requirement 9: Issue 1: The proposed requirement is too restrictive because it prevents the TOP from applying loss of life assumption on its equipment. We believe that entities should be able to determine when

exceeding equipment limits is appropriate based on the situation and equipment. Suggested Modification: - The TOP may exceed (real-time) a SOL for a continuous duration of 30 minutes. In addition we believe that the TOP should be allowed to use the IROL Tv concept to allow an SOL to be exceeded for a continuous duration of greater then 30 minutes if they notify the RC of the longer SOL Tv. Requirement 10: It is not clear as to when the notifications must take place. Would notifying the RC following the exceedance of the IROL or SOL be okay, or, must the TOP contact the RC prior to taking action in order to be compliant with this requirement? Requirement 12: ATC believes that this requirement is unnecessary because it is only saying that a TOP has to know what is going on with its system. In order to be compliant with the other requirements in this standard a TOP understands that by default they must monitor as appropriate its system. The challenge this requirement introduces is that it is so broad that demonstration of compliance is overly burdensome. In addition this requirement is unclear as to what and how often the TOP has to monitor, or have access to information to demonstrate compliance. Questions: If a TOP has a 4 second scan rate for EMS data and if a single data scan is missed or an error occurs at a single point does this mean that the TOP is non-compliant? If an entity uses information on a RC website about planned outages and for some time that system is unavailable for any length of time will the TOP be non-compliant because they don't have access to information? What does the requirement mean by the phrase "conditions and Facilities"? Does this mean that the ROP has to monitor breaker statues, switch statues, transformer temperatures, wind conditions and ambient temperatures? Proposed suggestion: ATC believes that this requirement should be deleted. Requirement 13: This requirement will reduce reliability because it will force TOP's to use the smallest base case model to perform its Operational Planning Analysis. We believe our statement is accurate because it requires the TOP to have an EMS model that matches the Operational Planning Analysis model. So if an entity performs off-line studies (non EMS studies) that use the Eastern interconnection then they must also monitor or have accession to information for the Eastern Interconnection. Since access to all if information is highly unlike or unnecessary to gather the TOP will have to use the model contained in their EMS to perform Operational Planning Analysis. Although this may not necessary be a bad thing a TOP will loss the benefits of using the larger model to perform Operational Planning Analysis. If the RC performs the Operational Planning Analysis then by this requirement does the TOP have to monitor everything in the RC's Operational Planning Analysis model? Suggested Modification: ATC believes that this requirement should be deleted.
No
Rational Box: The SDT states that by definition Operational Planning Analysis includes Contingency Analysis. ATC does not agree with this statement and therefore we requests that the SDT removed this statement. Operation Planning Analysis: "An analysis of the expected system condition for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generation outages, equipment limitations, etc.)." The definition does not specifically call out contingency analysis but is specific that an Operations Planning Analysis is a next day study which can be performed any time from a day ahead to as much as 12 months ahead. Time Horizon: In TOP-001-2 Requirement 2 the SDT calls on Operations Planning Analysis to be performed and identifies it as either a Same-Day Operations, Real-Time Operations Time Horizon requirement. In TOP-002-3 Requirement 1 the SDT is calling for Operations Planning Analysis to be performed and identifies it as a Operations Planning Time Horizon. ATC finds it very confusing that the SDT is using this defined term in multiple Time Horizons and believes that a single time horizon be used for this term. Requirement 1: If a TOP were to perform an Operations Planning Analysis for TOP-001-2 then what different Operations Planning Analysis would a TOP have to do be in compliance with Requirement 1 of TOP-002-3? Requirement 2: ATC believes that Requirement 2 (TOP-002-3) conflicts with TOP-001-2 Requirement 9. Requirement 9 in TOP-001-2 allows a TOP to exceed an SOL for a continuous duration of 30 minutes but that same allowance is not provided in requirement 2. (Note: see ATC's comment to Question 1 requirement 9.) ATC believes that the same continuous duration time provided in Requirement 9 of TOP-001-2 be allowed in Requirement 2. Requirement 3: ATC believes that additional clarity is needed around the use of the term "role". We believe that this requirement is calling for TOP's to contact other Registered Entities if they have an "action" to perform in the plan. Is ATC's understanding of the term "role" consistent with the SDT's understanding? ATC also believes that the phrase "reliability entities" should be replaced with Registered Entities.
No
Requirement 1.1: ATC believes that requirement 1.1 is unnecessary and opens up other issues and therefore should be deleted from this standard. Long-term outage information while important is not directly related to EMS data. In addition, information about facilities that operate below 100 kV is beyond FPA 215 and is beyond NERC's jurisdiction.
There will be an adverse impact to reliability
Operational Planning Analysis: ATC is concerned with the use of the term Operational Planning Analysis in both TOP-001 and TOP-002. Once something is called an Operational Planning Analysis all associated requirements apply. Although the SDT is attempting to draw a distiction between contengency analysis which typically runs off and EMS and more traditiional PSS/E or power flow studies those requirements that talk about monitor or access to information apply equally. Example: If an entity chooses to uses a Eastern Interconnection base model to satisfy

TOP-002 Requirement 1 that entity would have to also have to be in compliance with TOP-001 Requirement 13. Requirement 13 states that the TOP has to monitor or have access to information about condition and Facilities. By default a TOP would have to have access to information about every facility in the Eastern Interconnection model in order to be in compliance with calling the study a Operational Planning Analysis and By using the same term to represent different study time frames causes a number of compliance issues with this standard. We suggest that the team either determines a single meaning for the term Operational Planning Analysis or clarifies the compliance obligations around the different time frames for Operational Planning Analysis.
Individual
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson
ERCOT ISO
No
R1 – ERCOT ISO does not agree with the addition of the word ‘identified’ because it implies each Reliability Directive needs to be preceded with an additional statement like “the following is a Reliability Directive”. In a true emergency, clear concise communication and an understanding of what action is required to mitigate the situation is necessary. The addition of another sentence before each required action delays communication. ERCOT ISO thinks a Reliability Directive should not have to be declared as such, prior to issuance. Compliance should not be measured by whether the System Operator remembered to state “this is a Reliability Directive”, but should be measured by whether the Reliability Directive was properly issued and three-part communication was utilized. NOTE: Requirements 1 and 2 are dependent upon the approval of the term Reliability Directive, which is being proposed by Project 2006-06 Reliability Coordination. R2 – Add Operations Planning to the Time Horizon because R1 includes Operations Planning in the Time Horizon. R1 and R2 occur in the same Time Horizons, since R1 requires an entity to comply to a Reliability Directive issued by a TOP and R2 requires an entity who cannot comply to notify the issuing TOP. NOTE: Requirements 1 and 2 are dependent upon the approval of the term Reliability Directive, which is being proposed by Project 2006-06 Reliability Coordination. R9 VSL – The TOP, when notifying the RC, should identify the appropriate Tv. The associated VSL should be high and not severe and should only be severe when multiple instances occur.
Yes
No
R1.1 – The phrase ‘to be exchanged’ seems to be unnecessary. M2 and M3 – These measures allude to evidence of information actually being distributed, yet some companies make information available to entities through website posting or other public forums. Please include showing proof of availability of information to an entity as an option in these measures. M4 – The last sentence should be revised to match the last sentence of M5. Consider rewording both M4 and M5 as follows: “The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled.” The R2 and R3 VSLs have percentage approaches, but the R4 and R5 VSLs are binary, even though there are multiple elements to data specifications referred to in R4 and R5. All four of these requirements should have percentage approaches. Similarly, there are requirements for the RC (in IRO-010) to document data specifications. The associated IRO-010 R1 and R2 VSLs also have a percentage based approach. To be consistent, the TOP-003-2 R4 and R5 VSLs need to be changed to the percentage based approach for consistency.
There will be no change to reliability
Group
Western Electricity Coordinating Council
Steve Rueckert
Under R1 of the standard the word “identified” is used to describe a specific type of Reliability Directive issued by the Transmission Operator. Who performs the work or makes the identification of an “identified” reliability directive? Why under R2 is the classification not carried on to describe the RC directive such as “of its inability to perform an IDENTIFIED Reliability Directive”?
There will be no change to reliability
Individual
Michael Gammon
Kansas City Power & Light

No
Requirements R3 & R5 requires TOP's to notify all other "affected" or have an "adverse reliability impact" TOP's of an emergency condition. The terms "affected" and "adverse reliability impact" is a debatable condition and subject to interpretation. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Recommend the requirement be modified to alert other TOP's whenever a TOP in an emergency condition becomes aware of operating conditions that would result in exceeding an SOL or IROL operating limits under N-1 contingency conditions for other TOP facilities. Modifications for these two requirements will result in subsequent changes to the Measures and VSL's for requirements R3 & R5.
Yes
No
Requirement R4 may be troublesome for small Registered Entities to meet the data requirements dictated by larger Registered Entities. The is no recognition of the limitations of data exchange capability with an entity. Recommend requirement R4 be modified to include "within the data exchange capabilities of the recipient of the data specification". Modifications here would result in changes to the Measure and VSL for requirement R4.
There will be no change to reliability

Consideration of Comments on Real-Time Operations — Project 2007-03

The Real-Time Operations SAR Drafting Team thanks all commenters who submitted comments on the 4th draft of the standards for Real-Time Operations – Project 2007-03. These standards were posted for a 30-day public comment period from August 4, 2010 through September 3, 2010. Stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 34 sets of comments, including comments from more 34 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

The SDT made a number of changes to requirements and measures based on industry comments and additional changes based on observations of a Quality Review team. Where a changes was made to a requirement, conforming changes were made to the associated measure and VSLs.

TOP-001-2:

- Requirement R2– added the word 'identified' to make it clear that it is only "identified Reliability Directives" included in the scope of the requirement. Added "Operations Planning" as an additional possible time horizon.
- Requirement R3 – changed 'of' to 'by' to correct a typographical error.
- Requirement R5 – changed 'coordinate' to 'inform;' changed 'coordination' to 'communications;' and replaced 'with those Transmission Operators' with 'those respective' for simplification.
- Requirement R6 – changed 'coordination' to 'notify;' added a phrase to be more specific about what functional entity to notify; changed 'telemetering' to 'telemetry' for clarity.
- Requirement R8 – changed 'local' to 'internal' to clarify that the scope is limited to the TOP's own area.
- Requirement R9 – changed the VRF from "high" to "medium."
- Requirement R11 – added a 30 minute constraint on the time to respond to an SOL supporting the TOP's internal reliability.
- Deleted Requirements R12 – R14 as these requirements related to facility capabilities and will now be addressed in a separate project. (Project 2009-02 Real-time Monitoring and Analysis Capabilities
- Added an explanation to justify the VSLs for R5.

TOP-002-3:

- Purpose – updated to more closely align with the requirements in the standard
- Updated the text box associated with Requirement R1 to clarify the expectation that the Operational Planning Analysis is required under all conditions.
- Requirement R2 - changed 'local' to 'internal' to clarify that the scope is limited to the TOP's own area.
- Requirement R3 – changed 'reliability' entity to 'registered entity' for additional clarity.
- Added an explanation to justify the VSLs for R3.

TOP-003-2:

- Requirement R1 – changed ‘have’ to ‘create’ for clarity; changed ‘equipment’ to ‘facilities;’ removed the language specifying that the outage information comes from the Transmission Operator or Balancing Authority.
- Requirement R4 – added the Transmission Operator as one of the entities that must provide requested data.
- Requirement R5 – merged into Requirement R4.
- Measures M2 and M3 – added web postings with acknowledgment as additional examples of acceptable evidence.
- Eliminated redundancies in VSLs for R2.

The SDT recommends that this project be moved forward to the balloting stage.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 315-439-1390 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X
2.	Group	Kenneth D. Brown	Public Service Enterprise Group Companies	X		X		X	X				
3.	Group	Brent.Ingebrigtson@eon-us.com	E.ON U.S.	X		X		X	X				
4.	Group	Marie Knox	Midwest ISO Standards Collaborators	X									
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
6.	Group	Sandra Shaffer	PacifiCorp	X		X		X					
7.	Group	Mike Hardy	SERC OC Standards Review Group	X		X		X					
8.	Group	JT Wood	Southern Company Transmission	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				
10.	Group	Louis Slade, Jr.	Dominion	X		X		X	X				
11.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
12.	Group	Patrick Brown	PJM		X								
13.	Group	Ben Li	IRC Standards Review Committee		X								
14.	Group	Steve Rueckert	Western Electricity Coordinating Council										X
15.	Individuals	L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson			X								
16.	Individual	Dan Rochester			X								
17.	Individual	Joylyn Faust				X	X	X					
18.	Individual	John Fish						X					
19.	Individual	Jonathan Appelbaum		X									
20.	Individual	Kasia Mihalchuk		X		X		X	X				
21.	Individual	Jon Kapitz		X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Howard Rulf				X	X	X					
23.	Individual	RoLynda Shumpert		X		X		X	X				
24.	Individual	Greg Rowland		X		X		X	X				
25.	Individual	Michael Lombardi		X		X		X					
26.	Individual	Leland McMillan		X		X		X					
27.	Individual	Richard Kafka		X		X		X	X				
28.	Individual	Saurabh Saksena		X		X							
29.	Individual	Randi Woodward		X									
30.	Individual	Darryl Curtis		X									
31.	Individual	Catherine Koch		X									
32.	Individual	Terry Harbour		X									
33.	Individual	Jason Shaver		X									
34.	Individual	Michael Gammon		X		X		X	X				

1. TOP-001-2: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: As shown below, the SDT made a number of changes to requirements based on industry comments. All changes were semantic to provide additional clarity.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

R5. Each Transmission Operator ~~and Generator Operator~~ shall ~~coordinate~~ inform other Transmission Operators of its ~~respective~~ operations known or expected ~~by the Transmission Operator~~ to ~~have~~result in ~~a reliability impact~~ an Adverse Reliability Impact on ~~the portion of the BES of other~~ those respective ~~reliability entities~~Transmission Operator Areas with those ~~entities~~ Transmission Operators unless conditions do not permit such ~~coordination~~communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load,

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 within 30 minutes.

M5. Each Transmission Operator shall make available upon request, evidence that ~~operations~~ it ~~coordinated~~ informed other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas ~~with those Transmission Operators~~ in accordance with Requirement R5 unless conditions did not permit such ~~coordination~~ communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M8. Each Transmission Operator shall make available evidence that it has informed it~~'~~s Reliability Coordinator of each SOL~~s~~ which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

Organization	Yes or No	Question 1 Comment

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>Public Service Enterprise Group Companies</td><td>No</td><td>In R1 the word "identified" was added as an adjective to describe "Reliability Directive." While this is a step in the right direction, it needs further clarification. The requirement should be further modified to indicate that the Transmission Operator must indentify. i.e., state that "this is Reliability Directive" to ensure that the entities that must comply with this requirement know that what is being communicated by the TOP is a Reliability Directive and not some other less urgent communication.</td></tr>
<tr><td colspan="3">Response: “Reliability Directive” is not meant to equate to the urgency of a situation; rather it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator’s request or is debating the request can be “made to” cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views a Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to affect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made.</td></tr>
<tr><td>E.ON U.S.</td><td>No</td><td>E.ON U.S. suggests that in the definition of directive the adjective “mandated” should be added and placed in front of “action.”</td></tr>
<tr><td colspan="3">Response: Revision to the definition is not in the scope of this standard. The Definition of Terms for TOP-001-2 states the “…definition (of Reliability Directive) is included here for ease of reference…” and that the Reliability Coordination SDT (Project 2006-06) is writing the definition and will post that definition for vetting by the Industry. The SDT would note that Requirement R1 states that entities “shall comply” with identified Reliability Directives. Thus, by identifying the action as a Reliability Directive, the requirement is mandating the action. No change made.</td></tr>
<tr><td>Midwest ISO Standards Collaborators</td><td>No</td><td>Requirement #1 Comments cannot be developed for this requirement until we are able to see a final draft of the definition of Reliability Directive. It will have a significant impact on this requirement.

Requirement #9 SOL’s have not been defined clearly enough to require an identified time limit for exceedance. These durations could be set by the Transmission Owners or Operators based on the type of equipment, not dictated in the standard.

Requirement #10 It is not clear when the RC should be informed, before, during or after actions have been taken to correct an overload. This needs to be discussed. Depending on the urgency of the situation, it may not be appropriate for the TOP to inform the RC prior to taking actions. It should simply be a requirement for the TOP to log or record actions taken for future review.

Requirement #13 It is not clear what TOP area needs to be monitored. Language needs to be added to clearly state that a TOP should have access to information on other TOP areas that could impact the local area.</td></tr>
<tr><td colspan="3">Response: <u>Requirement 1 - </u>The SDT understands the perspective for the Requirement R1 comment, however, as pointed out in the Definition of Terms for TOP-</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
001-2, the "…definition (of Reliability Directive) is included here for ease of reference…" and the Reliability Coordination SDT (Project 2006-06) is writing the definition and will post that definition for vetting by the Industry. The SDT drafted the words such that the definition is secondary to the requirement. As written, the Transmission Operator would only "identify" an action as a Reliability Directive when the Transmission Operator "needs" an additional incentive to cut off discussion about whether or not the requested entity should carry out the action. If the entity carries out the action without the Transmission Operator identifying the action as a Reliability Directive, then the definition is not important. If the entity is not carrying out the requested action, then by identifying the requested action as a Reliability Directive, then the entity must comply – and again the definition is not critical to the requirement. Requirement R1 is designed to make clear that any request designated as a Reliability Directive must be carried out as stated (and repeated back). The definition only restricts the Transmission Operator in that the request must be necessary "to address an emergency." That allows the Transmission Operator to issue a Reliability Directive to respond to an Emergency and also during normal times, if needed, to preclude an Emergency condition from arising. Requirement 9 - The 30 minute limit is generally recognized as a time related to the risk of a second event occurring; thus 30 minutes is the maximum time. That does not preclude an operator from choosing a shorter duration (lesser restriction – e.g., higher MW) limit and using a shorter duration. No change made. Requirement 10 - The requirement does define an explicit time. It is the time after an action was taken ("…inform … of its actions…") and after the limit was exceeded ("…to return…when an IROL …has been exceeded…"). The communication therefore is not mandated prior to the action being taken. The fact that the communications are about "all of its actions" precludes communications "during" the action; thus leaving the communications to the post-action time period. No change made. Requirement 13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Bonneville Power Administration	No	R5 - should refer to adjacent Transmission Operators. R8 - This daily documentation is burdensome. Reporting "all" SOL's to RC ahead of time as part of daily assessment in addition to the daily planned outage heads-up reporting. Suggest clarifying SOL as intended to be path loading limits and/or local area transmission service support limits, (the BES is a big system with lots of ratings, it can also mean voltage limits in addition to line and path limits). If there is a significant change to a limit, that would be important. R10 - Prefer having the RC call the TOP in 5 Minutes to ensure entity is aware of and acting on a limit excursion , rather than TOP interrupt system response to call RC to tell them the Operator is mitigating a SOL violation which is a already a NERC TOP standard to take immediate action. There's a typo in M12, M13, M14 when it refers to the wrong requirement due to renumbering R11 instead of R12, R12 vs. R13, and R13 vs. R14).
Response: Requirement 5 - The requirement limits the coordination to those Transmission Operators that the former Transmission Operator "knows" are impacted. If a Transmission Operator "knows" it will impact a non-adjacent Transmission Operator, then that fact should be communicated per this requirement. The requirement does not mandate direct communication – it can be handled through third party Transmission Operators – but it must be communicated. No		

Organization	Yes or No	Question 1 Comment
change made. Requirement 8 - The requirement does not specify “daily”. The reference to “significant change to a limit” must be defined by BPA before the SDT can address the comment further. No change made. Requirement 10 - The requirement does define an explicit time. It is the time after an act was taken (“…inform … of its actions…”) and after the limit was exceeded (“…to return…when an IROL …has been exceeded…”). The communication therefore is not mandated prior to the action being taken. The fact that the communications is about all of its actions precludes communications “during” the action; thus leaving the communications to the post action time period. No change made. The SDT did not see a need to be prescriptive about the reporting time. The proper phrase would be “as soon as time permits” but that phrase does not provide the clarity that compliance enforcers desire. No change made. The SDT corrected the typos in the Measures.		
SERC OC Standards Review Group	No	In R2, it appears that an entity might be faced with double jeopardy if it fails to notify the entity issuing the directive. Doesn’t R1 also include this same requirement? In R3, the phrase “affected of actual’ should be “affected by actual”. In R8 and M8, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”. In R12 and R13, it doesn’t seem possible to measure “monitoring”. These also seem like requirements that are ideally suited for the certification process. It appears that the numbering of the requirements within each measure may have gotten out of synch due to a cut and paste insert. In M8, SOLs should be singular. The data retention periods are too long and do not appear to serve the purpose of improving reliability. Specifically, the three (3) year retention period for SOL and IROL violations is two (2) years too long.
Response: Requirements 1 & 2 - Requirement R1 is written to address a priori prohibitions. This would be communicated at the time the actions were first being communicated. Requirement R2 is written to address conditions that arise after the entity agreed to do the action but found out later that conditions preclude such actions. No change made. Requirement 3 - Requirement was revised as requested. **R3.** Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. Requirement 8 - Local area reliability is not a defined term but rather (as stated in the requirement) it is “based on its (the Transmission Operator’s own)		

Organization	Yes or No	Question 1 Comment
assessment." The industry has debated this issue for a long time. This standard is written to ensure BES reliability by defining IROLs and to supporting individual Transmission Operators parochial definitions. The loss of a capital city in a state may have no impact at all on the BES, but politically that city is critical (think Washington, DC). Requirement R8 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). No change made. Requirements 12 & 13 – These requirements have been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT revised the Measures for the editorial errors as noted.. An entity need only keep the exception cases where actual violations have occurred, which should be a minimal amount of data. No change made.		
Southern Company Transmission	No	Southern's comments: Suggest modifying R3 language for additional clarity. Suggested alternatives might be "Each Transmission Operator shall inform its Reliability Coordinator of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis, and shall likewise inform any other Transmission Operators that are known or expected to be affected by those Emergencies" or "Each Transmission Operator shall inform its Reliability Coordinator and all other expectedly affected Transmission Operators of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis." In the first sentence of M5, the first usage of the word "operations" is redundant and can be struck. In R8, it is unclear what should be the treatment of SOLs that develop due to unanticipated system conditions that are not included in the Operation Planning analysis (i.e., real time system conditions deteriorate due to several unplanned outages). In R11, need to add "...within 30 minutes" after SOL. R14 can be mis-read to mean that the Transmission Operator grants approvals of outages, as opposed to granting the authority to grant approval to the System Operator. Also, it would be useful to clarify if the TOP still has the authority to also veto planned outages, in addition to the System Operator having that authority. M11 - M14 have references to incorrect Requirement numbers. In M8 and M14, the word "its" was incorrectly modified to "it's." SERC's comments: Southern participated in developing these comments and support them In R2, it appears that an entity might be faced with double jeopardy if it fails to notify the entity issuing the directive. Doesn't R1 also include this same requirement?

Organization	Yes or No	Question 1 Comment
		In R3, the phrase “affected of actual’ should be “affected by actual”. In R8 and M8, what is the meaning of “local area reliability” and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word “supporting’ could be replaced by the phrase “necessary for”. In R12 and R13, it doesn’t seem possible to measure “monitoring”. These also seem like requirements that are ideally suited for the certification process. It appears that the numbering of the requirements within each measure may have gotten out of synch due to a cut and paste insert. In M8, SOLs should be singular. The data retention periods are too long and do not appear to serve the purpose of improving reliability. Specifically, the three (3) year retention period for SOL and IROL violations is two (2) years too long.

Response: Requirement R3 - In the case of Requirement R3, clarity of the text is difficult. First, the SDT offers what the words were meant to state: A Transmission Operator is mandated to contact its Reliability Coordinator about System conditions that either have caused the Transmission Operator to initiate Emergency procedures, or may cause the Transmission Operator to initiate Emergency procedures. Requirement R3 extends that contact to other Transmission Operators that either were identified in the Operational Planning Analysis (OPA) as being affected or the Transmission Operator knows is being affected. The wording is crafted to eliminate the possibility that an auditor would find the Transmission Operator non-compliant when another Transmission Operator not previously identified in any study or any procedure was affected. The words state that if you ‘know or expect’ impacts on someone than you must contact them to prepare them for the conditions, but if you don’t know or expect an entity to be affected, then the requirement does not apply.

Discussion of alternatives: The known or expected is a modifier to “other Transmission Operators.” The idea was that the Operating Plan would define the expected; the “known’ was to address the fact that a condition could arise that was not expected, but the Transmission Operator now ‘knows’ (from some other means) that another Transmission Operator (not known from the OPA) was affected. This phraseology was meant to capture that situation where a Transmission Operator finds out a fact that is not in its study. The requirement does not excuse the Transmission Operator just because the other Transmission Operator was not in the analysis – if you ‘know’ then you are required to contact them. On the other hand, if another Transmission Operator is impacted but your OPA did not identify that impact and you don’t have any knowledge of the impact, then Requirement R3 does not apply.

Given the above discussion, alternative 2 would not add clarity – since the “known or expected” modifies Emergency. No change made.

Measure M5 – The SDT agrees and has revised the measure accordingly.

> **M5**. Each Transmission Operator shall make available upon request, evidence that ~~operations~~ it ~~coordinated~~ informed other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas ~~with those Transmission Operators~~ in accordance with Requirement R5 unless conditions did not permit such ~~coordination~~ communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

Requirement R8 - Requirement R8 is a pre-event reporting requirement. This requirement is strictly focused on what to do with the SOLs that are pre-assigned.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">The requirement says if a Transmission Operator wants to address an SOL on the same level as an IROL, then it must inform the Reliability Coordinator of which SOLs are to be raised to that level. Thus, exceedances of SOLs that arise and were not identified in the Operational Planning Analysis will not be covered in Requirement R8. No change made.

Requirement R11 – The SDT agrees and has added “within 30 minutes”

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s T_v, or of an SOL identified in Requirement R8 within 30 minutes.

Requirement R14 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

The SDT corrected typos including Measure 8.

M8. Each Transmission Operator shall make available evidence that it has informed it~~'~~s Reliability Coordinator of each SOL~~s~~ which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

For SERC comments, see SERC response.</td></tr>
<tr><td>FirstEnergy</td><td>No</td><td>We agree with many of the changes the drafting team made to this standard. However, we have the following comments and suggestions: a. With respect to R7 and R11 in relationship to IROLs, R11 is inherent in R7. If an entity is not permitted to operate outside an IROL limit for longer than its Tv, then it needs to implement whatever actions are required to comply with Tv including directing "others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv."

R9 and R11 have the same issue with respect to SOL's.

M3 is silent on evidence related to the Operational Planning Analysis. Did the drafting team intend for this data to be available for inspection as a means of proving or disproving the affect on a Neighboring Transmission Operator and thereby the need to contact them? If it is the intent of the drafting team to use the Operational Planning Analysis as evidence, then it should be specifically stated in M3. If it is the intent of the drafting team for an entity to be able to prove "conditions did not permit such coordination" then that evidence should be specified in the measures.

b. R11 - We believe that requiring the TOP to mitigate IROLs is outside their scope per the functional model. The RC holds the authority over the tools needed to mitigate an IROL and is the appropriate entity responsible for this requirement. Also, it seems as though this requirement is duplicative of IRO-009-1 R4 which states "When actual system conditions show that there is an instance of exceeding an IROL in its Reliability Coordinator Area, the Reliability Coordinator shall, without delay, act or direct others to act to</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		mitigate the magnitude and duration of the instance of exceeding that IROL within the IROL's Tv. (Violation Risk Factor: High) (Time Horizon: Real-time Operations)". c. R13 - We suggest the team remove the phrase "within any Transmission Operator Area" from the requirement. We believe this phrase is not necessary and adds confusion. d. R14 - The original SAR charged with addressing Order 693 directive 1660 required the standards to identify the minimum monitoring and analysis capabilities. The new requirement R14 does not fully address these minimum capabilities and will leave the requirement ambiguous from a compliance and enforcement standpoint. We suggest the team fully address the directive and clarify the requirement. e. Measures M10 through M14 make reference to the wrong requirements.
Response: a. The industry has agreed that violations of IROLs must never occur – hence Requirement R7. Requirement R7 is meant as a flat-out prohibition on violating IROLs – the concept being that IROL violations will/may take down the BES. The industry also seems supportive of extending the IROL violation to some (some would even like to extend the prohibition to all) SOLs which the Transmission Operator decides are important at the local level, hence Requirement R9. Requirement R11 is an action requirement that mandates not just avoiding a violation (Requirements R7 & R9) but to reduce any and all exceedances. The SDT interpreted the industry as wanting to prohibit the Transmission Operator not just to stay within the MW and time margins, but also wanted the Transmission Operators to act when any magnitude limit is exceeded no matter how short a time. Requirement R11 mandates that once the magnitude is exceeded, the Transmission Operator must be taking action. Requirements R7 and R9 force the Transmission Operators to be concerned with any and all System conditions that "can" lead to going over the magnitude and duration limit. While not mandating a multiple Contingency standard, these two requirements force Transmission Operators to be sensitive to (i.e., not ignore) conditions that may result in common mode failures that would not occur during normal conditions. No change made. Measure M3 – The requirement is to 'inform' and the SDT believes that the measure correctly states what evidence is needed to prove that an entity 'informed'. No change made. b. The SDT believes that there are situations where the Transmission Operator must take actions or direct others to act over and above those situations where the Reliability Coordinator does same. No change made. c. This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. d. This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. e. The SDT has corrected the typos.		
Dominion	No	Agree with changes to most requirements and measures, but with exceptions as noted below: R2 - Is covered in R1. Do not agree with entity being subject to non-compliance for same shortcoming under 2 requirements. We suggest R2 be removed or that R1 and R2 be revised so that the requirement to inform the TOP not be included in both. R13 - Is the sentence meant imply that a TOP should monitor or have access to information/facilities in

Organization	Yes or No	Question 1 Comment
		another TOP Area that could impact its TOP Area? If so, we believe the current draft language should be revised to improve clarity of intent. We suggest revising to read “Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within external Transmission Operator Area(s) as necessary to perform such analysis” M1/M2 - revise measures so that entity is not subject to non-compliance for failure to notify TOP twice, pursuant to changes in R1/R2. M8 - change SOLs to SOL. M13 - revise pursuant to R13.

Response: Requirements R1 & R2 (and Measures M1 & M2) - Requirement R1 is written to address a priori prohibitions. These would be communicated at the time the actions were first being communicated. Requirement R2 is written to address conditions that arise after the entity agreed to do the action but found out later that conditions preclude such actions. No change made.

Requirement R13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

M8 – The SDT made the indicated revision.

> **M8**. Each Transmission Operator shall make available evidence that it has informed it~~'~~s Reliability Coordinator of each SOL~~s~~ which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

Organization	Yes or No	Question 1 Comment
Terry Harbour	No	The proposed TOP-001-2 standard is a significant improvement, but there are still important items that need to be addressed including: Comments cannot be developed for this requirement until a final draft of the definition of Reliability Directive is presented as it will have a significant impact on TOP-001-2 and R1. When Reliability directive is defined, the definition of a Reliability Directive is too broad and should be limited to “Abnormal conditions that require operational actions to avoid instability, uncontrolled separation and cascading as defined in Section 215 of the Federal Power Act.” TOP-001-2-R9: SOL’s should not be part of the TOP-001-2 standard as there are not identified timeframes in the NERC standards today. However, if SOL’s must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded such as 30 minutes after exceeding the specified SOL limit. An example definition might be non-thermal SOL’s are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability. Many times scheduled transmission outages coupled with weather (drought, wind front, heat wave, etc) and strong market moves can drive unexpected SOL exceedances where units and markets cannot move within

Organization	Yes or No	Question 1 Comment
		30 minutes to redispatch sufficient generation. Coupling SOLs with time frames and penalties will drive unforeseen market impacts. TOP-001-2-R10: It isn't clear when the RC should be informed, before, during, or after actions have been taken to correct an overload. Depending upon the urgency of the situation, it might not be important to notify the RC, therefore the requirement should be changed to the TOP should record actions taken for future review. For TOP-001-2-R6 replace "coordinate" with "notify the RC and negatively impacted adjacent interconnected NERC registered entities of " For TOP-001-2-R3, the words "and anticipated" needs to be dropped as an unmeasurable requirement. In TOP-001-2-R2 and R4, "expected to be affected" would include known. We asked the SDT to please strike known. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for TOP-001-2-R5 and R8 need to be clear that these are event driven requirements and evidence is only required if an "event" has occurred. In R6, the word "telemetering" should be capitalized as it is a defined term in the NERC Glossary. The terms "control equipment" and "associated communications channels" are not defined in the glossary at all. Recommend modifying the wording to ensure consistency between standards. R14 uses the term "monitoring and analysis capabilities". This term is not defined in the NERC Glossary. R13 implies that a TO's Operational Planning Analyses should be monitoring facilities external to its own operating area when they have no control or responsibility for said facilities. It is not a TO's responsibility to monitor regional system conditions; therefore this requirement should be removed. FERC Order 693, paragraphs 1660 and 1661 do not specifically mention any of the verbiage in requirements R12, R13, & R14; therefore the preceding statement should be considered.

Response: "Reliability Directive" is not meant to equate to urgency of a situation; rather it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the

Organization	Yes or No	Question 1 Comment

phraseology would raise the text to the same level as an act to relieve the condition itself. No change made.

Requirement R9 - The 30 minute limit is generally recognized as a time related to the risk of a second event occurring, thus 30 minutes is the maximum time. That does not preclude an operator from choosing a shorter duration (lesser restriction – e.g., higher MW) limit and using a shorter duration. No change made.

Requirement R10 - The requirement does define an explicit time. It is the time after an act was taken ("…inform … of its actions…") and after the limit was exceeded ("…to return…when an IROL …has been exceeded…" The communication therefore is not mandated prior to the action being taken. The fact that the communication is about all of its actions precludes communication "during" the action; thus leaving the communications to the post-action time period. The SDT did not see a need to be prescriptive about the reporting time. The proper phrase would be "as soon as time permits," but that phrase does not provide the clarity that compliance enforcer's desire. No change made.

Requirement R6 – The SDT agrees and has revised the wording accordingly.

> **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

Requirement R3 - From a compliance auditor's perspective, the auditor is constrained to depend on the Transmission Operator on whether or not an Emergency is "anticipated". The rationale for the language was to put the Transmission Operator on alert that even the expectation of an Emergency is enough to trigger communications.

Requirement R2 & R4 - Without the phrase "expected to be affected," the requirement would only apply in the case of actual Emergencies (which may be too late to make use of all available options). A real Emergency that is known to impact Transmission Operator X may not necessarily have been shown by the OPA to affect Transmission Operator X. This requirement is written in a way that it does not excuse a Transmission Operator that runs an OPA that has no problems, from its obligation to contact others that it knows are de facto affected. No change made.

Requirement R7 - The issue of percentages was discussed and was evaluated not to be strong enough for this situation. One violation is unacceptable. More than 4 violations of a requirement that addresses BES so directly cannot be mitigated by percentages. No matter how big or how small a Transmission Operator is, non-compliance with this requirement cannot be justified. No change made.

Requirements R5 & 8 – The SDT believes that the wording is correct as stated. No change made.

Requirement R6 – The SDT has changed the wording for clarity.

Requirement R14 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

Requirement R13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

Requirements R12 & R13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

Organization	Yes or No	Question 1 Comment
MRO's NERC Standards Review Subcommittee	No	The proposed TOP-001-2 standard is a significant improvement, but there are still important items that need to be addressed including: Comments cannot be developed for this requirement until a final draft of the definition of Reliability Directive is presented as it will have a significant impact on TOP-001-2 and R1. When Reliability directive is defined, the definition of a Reliability Directive is too broad and should be limited to "Abnormal conditions that require operational actions to avoid instability, uncontrolled separation and cascading as defined in Section 215 of the Federal Power Act." TOP-001-2-R9: SOL's should not be part of the TOP-001-2 standard as there are not identified timeframes in the NERC standards today. However, if SOL's must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded such as 30 minutes after exceeding the specified SOL limit. An example definition might be non-thermal SOL's are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability. TOP-001-2-R10: It isn't clear when the RC should be informed, before, during, or after actions have been taken to correct an overload. Depending upon the urgency of the situation, it might not be important to notify the RC, therefore the requirement should be changed to the TOP should record actions taken for future review. For TOP-001-2-R6 replace "coordinate" with "notify the RC and negatively impacted adjacent interconnected NERC registered entities of" For TOP-001-2-R3, the words "and anticipated" needs to be dropped as an unmeasurable requirement. In TOP-001-2-R2 and R4, "expected to be affected" would include known. We asked the SDT to please strike known. The VSLs for R7 appear to assume that the sample set of SOLs that would be reported to the RC is a small number by using one, two, three and four in each successive VSL. What if the sample set is large (i.e. 1000 SOLs)? Should the VSLs be based on percentages? The measures for TOP-001-2-R5 and R8 need to be clear that these are event driven requirements and evidence is only required if an "event" has occurred. In R6, the word "telemetering" should be capitalized as it is a defined term in the NERC Glossary. The terms "control equipment" and "associated communications channels" are not defined in the glossary at all. Recommend modifying the wording to ensure consistency between standards. R14 uses the term "monitoring and analysis capabilities". This term is not defined in the NERC Glossary. R13 implies that a TO's Operational Planning Analyses should be monitoring facilities external to its own operating area when they have no control or responsibility for said facilities. It is not a TO's responsibility to

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		monitor regional system conditions; therefore this requirement should be removed. FERC Order 693, paragraphs 1660 and 1661 do not specifically mention any of the verbiage in requirements R12, R13, & R14; therefore the preceding statement should be considered.

Response: "Reliability Directive" is not meant to equate to urgency of a situation; rather it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made.

Requirement R9 - The 30 minute limit is generally recognized as a time related to the risk of a second event occurring, thus 30 minutes is the maximum time. That does not preclude an operator from choosing a shorter duration (lesser restriction – e.g., higher MW) limit and using a shorter duration. No change made.

Requirement R10 - The requirement does define an explicit time. It is the time after an act was taken ("…inform … of its actions…") and after the limit was exceeded ("…to return…when an IROL …has been exceeded…" The communication therefore is not mandated prior to the action being taken. The fact that the communication is about all of its actions precludes communication "during" the action; thus leaving the communications to the post-action time period. The SDT did not see a need to be prescriptive about the reporting time. The proper phrase would be "as soon as time permits," but that phrase does not provide the clarity that compliance enforcer's desire. No change made.

Requirement R6 – The SDT agrees and has revised the wording accordingly.

> **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

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Requirement R7 VSLs - The issue of percentages was discussed and was evaluated not to be strong enough for this situation. One violation is unacceptable. More than 4 violations of a requirement that addresses BES so directly cannot be mitigated by percentages. No matter how big or how small a Transmission Operator is, non-compliance with this requirement cannot be justified. No change made.

Requirements R5 & 8 – The SDT believes that the wording is correct as stated. No change made.

Organization	Yes or No	Question 1 Comment
Requirement R6 – The SDT has changed the wording for clarity. Requirement R14 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirement R13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirements R12 & R13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
PJM	No	There are several issues with Requirement 6: o The requirement assigns responsibility to 3 entities for one task. NERC standards are designed to clearly assign responsibility to provide a clear measurement and allocation of non-compliance. R 6 as worded requires “coordination” between and among each entity. • Coordination is not defined. Does coordination mean “informing” another party? Does it mean “directing a new solution”? Does it mean “asking permission” of a third party? Who is non-compliant when two (or more) parties do not agree with a proposed solution? How many alternatives proposals must be considered? Suggest the requirement be rewritten as a series of independent requirements with sub-bullets to identify specific tasks. Example: Each TOP shall inform all affected reliability entities of planned outages of active real-time communications channels: o Interpersonal channels • Data exchange channels for any BES elements or elements involved in identified IROL computations • Asset direct-control devices (reactive control equipment,...) Each TOP shall inform all affected parties of alternative means to be used for the duration of the proposed outage. Each BA shall inform all affected reliability entities of planned outages of active real-time communications channels: o Interpersonal channels o Data exchange channels for any BES elements or elements involved in identified IROL computations o Asset direct-control devices (regulation control signals; resource dispatch equipment,...)Each GOP shall inform all affected reliability entities of planned outages of active real-time communications channels: o Interpersonal channels o Data exchange channels for any BES elements or elements involved in identified IROL computations o Asset direct-control devices Each reliability entity inform by the TOP in Rx.x, (or by the BA in Ry.y or by the

Organization	Yes or No	Question 1 Comment
		GOP in Rz.z) shall acknowledge the receipt of the information provided in Rx.x (or in Ry.y or Rz.z) to the respective TOP (BA or GOP). Requirement #13Delete the phrase "...within ANY Transmission Operator Area". The phrase has the potential to add confusion rather than clarity to the requirement.
Response: Requirement R6 – The SDT has modified the requirement to address your concern. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. Requirement R13 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
IRC Standards Review Committee	No	Requirement #1 Comments cannot be developed for this requirement until we are able to see a final draft of the definition of Reliability Directive. It will have a significant impact on this requirement. Requirement #9 A 30-minute time limit has been identified in Requirement 9, but that may be an inappropriate time based upon the variability that exists with actual system operating limits. In the case of thermal limits, some may be 15 minutes others may be 4 hours for different facilities. The same facility may have a 4 hour loading limit, and a 2 hour limit at a higher magnitude, as well as, perhaps, a 30 minute limit at a higher magnitude yet. If the limits were allowed to only be set at 30 minutes, how are longer limits incorporated? Of course it is imprudent to operate a facility at the magnitude corresponding to a four hour limit for greater than four hours. But how is that limit identified and communicated if the System Operating Limit must be mitigated within 30 minutes? Any such operating parameter will be recognized as an SOL, then requiring a 30 minute limit if Requirement 9 is left as is. Requirement 8 mandates that limits be set to support local area reliability. Operating a facility for five hours at its four hour limit is contrary to that requirement. Transmission Operators need SOLs to be described and communicated in terms of both magnitude and associated time, but that time need not be limited to 30 minutes. The duration and magnitude of the SOL should be set by the Transmission Owners or Operators based upon respecting the facility and equipment ratings as required by the FAC standards. Requirement 9 would better serve reliability to require SOLs (which are identified in Requirement 8) to be described in specific terms of both magnitude and associated time. If needed, a fallback position could be maintained that establishes 30 minutes as the default time limit if no other limit is specifically defined in the SOL.

Organization	Yes or No	Question 1 Comment
		Requirement #13 It is not clear what TOP area needs to be monitored. Language needs to be added to clearly state that a TOP should have access to information on other TOP areas that could impact his local area.
Response: **“**Reliability Directive” is not meant to equate to urgency of a situation; rather, it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator’s request or is debating the request can be “made to” to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made. Requirements R8 & 9 - The issue posed by the IRC seems to be more academic than real. Requirement R8 does not mandate that any SOL be defined. Requirement R8 only requires that a Transmission Operator tell its Reliability Coordinator of those SOLs that the Transmission Operator has decided it wants the Reliability Coordinator to treat in the same fashion as the Reliability Coordinator would treat IROLs. IRC is using its definition for SOL not the Requirement R8 definition. Requirement R8 defines SOL as a limit that the Transmission Operator itself has designated for monitoring and control by the Reliability Coordinator. Every operating limit does not automatically come under that requirement. However, if a Transmission Operator wants every operating limit to be addressed by the Reliability Coordinator in the same way that the Reliability Coordinator addresses IROLs, then that is allowed under this requirement. If the Transmission Operator wants none of its operating limits handled like an IROL, that too is allowed under the requirement. The Transmission Operator requirements protect the BES under the IROL requirements; these non-IROL limits are optional. NERC has used a 30-minute time frame for several Contingency-related standards based on a review that showed the risk of a second Contingency is greatly increased after 30 minutes. While a 4-hour rating may be used, if a single Contingency were to occur, there would be no problem, but a second Contingency would be a problem. While the requirement does not mandate reserves for multiple Contingencies, the requirement does impose a time frame of 30 minutes. There is no one SOL for a Facility. Each Facility has an infinite number of magnitude vs. duration curves. No change made. Requirement R13 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	No	R1 - ERCOT ISO does not agree with the addition of the word ‘identified’ because it implies each Reliability Directive needs to be preceded with an additional statement like “the following is a Reliability Directive”. In a true emergency, clear concise communication and an understanding of what action is required to mitigate the situation is necessary. The addition of another sentence before each required action delays communication. ERCOT ISO thinks a Reliability Directive should not have to be declared as such, prior to issuance. Compliance should not be measured by whether the System Operator remembered to state “this is a Reliability Directive”, but should be measured by whether the Reliability Directive was properly issued and three-part communication was utilized. NOTE: Requirements 1 and 2 are dependent upon the approval of the term Reliability Directive, which is being proposed by Project 2006-06 Reliability Coordination.

Organization	Yes or No	Question 1 Comment
		R2 - Add Operations Planning to the Time Horizon because R1 includes Operations Planning in the Time Horizon. R1 and R2 occur in the same Time Horizons, since R1 requires an entity to comply to a Reliability Directive issued by a TOP and R2 requires an entity who cannot comply to notify the issuing TOP.NOTE: Requirements 1 and 2 are dependent upon the approval of the term Reliability Directive, which is being proposed by Project 2006-06 Reliability Coordination. R9 VSL - The TOP, when notifying the RC, should identify the appropriate Tv. The associated VSL should be high and not severe and should only be severe when multiple instances occur.
Response: Reliability Directive is not meant to equate to urgency of a situation; rather, it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the System Operator. The exact words needed to effect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. Communications between registered entities occur almost continuously. Within those communications are instructions from Reliability Coordinators and Transmission Operators. Those instructions are expected to be followed at all times. However, there are times when people question instructions. At those times, the recipient of an instruction that is identified as a Reliability Directive needs a clear understanding that it is a Reliability Directive. The requirement is consistent with the ERCOT position that added words should not be mandated; the difference is that the ERCOT proposal would mandate the repeating of actions, whereas the requirement does not. No change made.. Requirement R2 – The SDT has added the time horizon as requested. **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]* Requirement R9 – If a VSL is binary, and the SDT believes that this VSL should be binary, it must be Severe. No change made.		
Joylyn Faust	No	R2 is ambiguous, must a BA inform it's TO of an inability to perform a directive after the directive has been issued or at anytime its systems are down and it has temporarily lost its ability to perform some function. R12-14 appear to provide the TO with omnipotent information rights which may include the ability to create monitoring requirements of other entities and control over maintenance schedules of other entities telemetry and associated facilities. Furthermore reciprocal data rights are not provided.
Response: Requirement 2 - R2 is an after-the-request requirement. If, after being given a Reliability Directive, the entity finds out that its equipment cannot perform as expected, Requirement R2 mandates the entity tell the Reliability Coordinator so that the Reliability Coordinator may make other arrangements. If the		

Organization	Yes or No	Question 1 Comment
system were down, then other NERC requirements mandate that such conditions be communicated. This requirement is just designed for states when the entity expects to be able to do something but finds out that it cannot. No change made. Requirements 12-13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Jonathan Appelbaum	No	“Operational Planning Analysis” is not a defined term in the NERC Glossary and a proposed definition is not included in the Draft Standard. TOP-001 and TOP-002 have capitalized the term indicating a definition. TOP-002 information box says “by definition Operational Planning Analysis includes Contingency Analysis.” TOP-001 R12 and R13 were added in this posting to address Order 693 paragraph 1660 and 1661 direction to include the minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the Bulk-Power System. The drafting team utilizes the phrase “shall monitor, or shall have access to information about, conditions and Facilities...” By offering an alternative to “monitor” the drafting team is implying there is a difference between “monitor” and “having access to information”. UI suggests retaining “monitor” and removing “access to information about” because the TOP needs the minimum capability of monitoring the Facilities in its area to perform its reliability functions.
Response: Operational Planning Analysis is in the Glossary. No change made. Requirements 12 and 13 have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Jon Kapitz	No	R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected of actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. Xcel Energy has concerns about the use of the term “affected”. This can be widely interpreted by the entity and compliance enforcement authority. We suggest that language limit the entity’s obligation to Adjacent entities and the Reliability Coordinator. The RC should be held responsible for making this assessment from a regional perspective and make notifications to other entities as it is required to or deems necessary. R13. Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. Xcel Energy has concerns as to whether this requirement indicates that a TOP must have monitoring capability for other TOP areas. This requirement should encompass only a TOP’s own area. R14. Each Transmission Operator shall provide approval rights for planned maintenance of its monitoring and analysis capabilities to its System Operators. Xcel Energy believes this requirement should be worded so that it covers only monitoring capabilities for its own area, and items that it is in control of. (e.g. not feeds from other entities that input into a TOPs own monitoring capability)

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>M11 through M14 list incorrect associated requirements. This appears to be a mapping issue.</td></tr>
<tr><td colspan="3">Response: <u>Requirement 3</u> - The SDT respects the sensitivity of regarding the term “affected.” The SDT perspective was to avoid the possibility that any and every ‘affect’ in Real-time would come under this requirement, and inserted the phrase “… expects to be affected…” This would mean that if the Transmission Operator “expected” to affect another entity, then Requirement R3 would require the Transmission Operator to communicate that expectation. However, if the Transmission Operator did not expect to impact a third-party, then there would be no obligation. As written, the requirement provides a common sense approach. To be found non-compliant, an auditor would have to show evidence that the Transmission Operator knew that there would be an impact and knowingly did not inform the impacted entity. This would require an auditor to peruse data and make a case. It is possible to show non-compliance, but it will be the auditor’s responsibility to prove that fact, as opposed to the Transmission Operator being subject to proving that. While the Reliability Coordinator is responsible for ensuring that every entity knows its role, this requirement recognizes that the Transmission Operator can have a role in analyses and information that may not be analyzed in the detail that the Transmission Operator can provide. No change made.

<u>Requirement 13</u> – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

<u>Requirement R14</u> – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.

The SDT has corrected the typos in the measures.</td></tr>
<tr><td>Howard Rulf</td><td>No</td><td>R7: What does it mean to be “outside” an IROL? Vague.

R8: Since any SOL is to “ensure operation within acceptable reliability criteria” this requirement requires that the TOP inform the RC of all SOLs. How can the Time Horizon be Real-Time Operations? Operational Planning Analysis is done at least day ahead?

R9: What does it mean to be “outside” an SOL? Vague.

R10: How do I correlate “within limits” to “inside/outside”?</td></tr>
<tr><td colspan="3">Response: <u>Requirements 7, 9, & 10 - </u>The term “outside” was used to recognize that there are both upper and lower limits. No change made.

<u>Requirement 8 – Requirement </u>R8 is an a priori requirement. All it is meant to say is “if a Transmission Operator wants its Reliability Coordinator to observe a given non-IROL limit in the same way as the Reliability Directive observes IROLs, then the Transmission Operator must tell that Reliability Coordinator which limits are in that category. This must be done ahead of time. It can be done in the OPA or in the Long-term planning horizon or any other advanced time – it cannot be done in Real-time (where Real-time is defined as ‘this instant’) or after-the-fact. No change made.</td></tr>
<tr><td>RoLynda Shumpert</td><td>No</td><td>In R3 the language should be "...be affected by actual..." and not "...be affected of actual..."

Measures M10-M14 are off by 1 in pointing back to their respective requirements (i.e. M10 is pointing back to</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		R9, etc). It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: Requirement 3 – The SDT has revised Requirement R3 to address your comment and those of others. **R3.** Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. The SDT has corrected the typos.		
Greg Rowland	No	What does the drafting team mean by "its inability" in R2 to perform a Reliability Directive? There clearly needs to be a distinct difference between the reasons in R1 and "inability" in R2. Duke wants to eliminate the possibility of double jeopardy for an entity to be assessed a possible violation for non-compliance to one action with it stated similarly in two requirements. R3 typo - change the word "of" to "by". R8 - the phrase "supporting its local area reliability" is unclear. Replace it with the phrase "having an Adverse Reliability Impact". This adds clarity and also recognizes that local area problems that don't rise to the level of Adverse Reliability Impact should not be treated as SOLs required to be reported to the RC under this standard. R9 - insert the phrase "as having an Adverse Reliability Impact" after the phrase "Requirement R8", making R9 consistent with R8. R13 - strike the phrase "shall monitor, or". The TOP doesn't need to directly monitor facilities in other TOP areas. M1 - strike the word "either" and replace the phrase "or, (b) informed the Transmission Operator that" with the word "unless". This makes M1 consistent with the R1 revision above. M3 typo - replace the word "of" with the word "by". M5 typo - the word "operations" appears twice. Need to strike the first one. M8 - replace the phrase "supporting its local area reliability" with the phrase "having an Adverse Reliability Impact", consistent with the R8 revision above. M13 - strike the phrase "can monitor, or" consistent with the R13 revision above. R1 VSL - replace the phrase "and the respective entity did not inform the Transmission Operator that such

Organization	Yes or No	Question 1 Comment
		action would" with the phrase "and compliance with the Reliability Directive would not", consistent with the R1 revision above. VSLs for R3, R5, R6 and R8 - The mixing of numbers with percentages and the phrase "whichever is less" in these VSLs is confusing. For example, if under R5 there are four affected entities, and the TOP does not coordinate operations with one of the four, then that is one entity, or 25% of the total. What does "whichever is less" mean? Is that a Lower or Severe violation? Conversely, if there is only one affected entity and the TOP does not coordinate operations with that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation? R8 VSLs - In each VSL, replace the phrase "supporting its local area reliability" with the phrase "having an Adverse Reliability Impact, consistent with the R8 revision above. R13 VSL - Strike the phrase "monitor, or", consistent with the R13 revision above.

Response: Requirements 1 & 2 - Requirement R1 is written to address a priori prohibitions. These would be communicated at the time the actions were first being communicated. Requirement R2 is written to address conditions that arise after the entity agreed to do the action, but found out later that conditions preclude such actions. No change made.

Requirement 3 – The SDT revised the requirement to address your comment.

> **R3.** Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~ by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.

Requirement 8 - Local area reliability is not a defined term but rather (as stated in the requirement) it is "based on its (the Transmission Operator's own) assessment." The industry has debated this issue for a long time. This standard is written to ensure BES reliability by defining IROLs and by supporting individual Transmission Operators parochial definitions. The loss of a capital city in a state may have no impact at all on the BES, but publicly that city is critical (think Washington, DC). Requirement R8 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). Given that the requirement is for local concerns that could mean that the limit is not necessary for local reliability but rather "supports" local reliability. No change made.

Requirement 9 - An SOL that has adverse reliability impacts is, by definition, an IROL. Requirement R8 says that if it isn't an IROL and you want the limit to be controlled in the same way as an IROL, then tell the Reliability Coordinator which limits you want. [Note what all this means –when running its planning and or operating analysis, the Reliability Coordinator does not find the said limit as causing any BES problems – thus the Reliability Coordinator is not concerned with the said limit. The Transmission Operator however, wants, or is required by some other authority, to treat the said limit as if that limit had BES implications. Such information must be conveyed by the Transmission Operator to the Reliability Coordinator.] Thus, inserting the proposed text will not accomplish the intent of the requirement. No change made.

Requirement 13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis

Organization	Yes or No	Question 1 Comment
Capabilities. The SDT reviewed the typos and made the changes where deemed appropriate. The mixing of numbers and percentages is standard for VSLs. It is designed to allow for size differences in applicable functional entities. 'Whichever is less' means simply that you use the option that is less numerically. No change made.		
Michael Lombardi	No	Both Requirements R12 and R13 are considered vague and open to interpretation. For example, what type of information is to be monitored and what is meant by conditions? Language needs to be added to clearly state what a TOP needs to accomplish pursuant with these requirements. Various Measures appear to have incorrect Requirement references. For example, the text of Measure M14 refers to Requirement R13. Please verify / correct the Requirement references for all Measures. The term "Operational Planning Analysis", is capitalized to identify it as a defined term yet the NERC Glossary of Terms (updated 4/20/2010) indicates that the term has not been FERC approved. NU is concerned that the terms Operational Planning and Operational Planning Analysis are not FERC approved and may not be consistently applied throughout the industry. Suggest these terms be reviewed as part of this standard to ensure industry consensus on these terms and subsequently seek FERC approval, as required.
Response: Requirements 12-13 - These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. The SDT has corrected the typos. Operational Planning Analysis is contained in the NERC Glossary. Once it is approved by the BOT, the SDT is required to use the term. No change made.		
Richard Kafka	No	R6 requires coordination which leads to questions regarding who is non-compliant. It would be more proper to require reporting and approval requirements. RCs already are required to coordinate with each other. R9 sets a 30 minute limit on all identified SOLs (as opposed to allowing different times). This would require all facilities to have the same time limits for ratings. That should be addressed in FAC-008.
Response: The SDT has revised Requirement R6 to address your concerns. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. NERC has used a 30-minute time frame for several Contingency-related standards based on a review that showed the risk of a second Contingency is greatly increased after 30 minutes. While a 4-hour rating may be being used, if a single Contingency were to occur, there would be no problem, but a second		

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Contingency would be a problem. While the requirement does not mandate reserves for multiple Contingencies, the requirement does impose a time frame of 30 minutes. There is no one SOL for a Facility. Each Facility has an infinite number of magnitudes vs. duration curves. No change made.		
Saurabh Saksena	No	R13 states that - Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. What does "Facilities" in R13 refer to? Is it any facilities that are included in the analysis or those that have the potential to cause violations? Suggest replacing "...Facilities identified in its Operational Planning Analysis" by text in R8 - "...identified by the Transmission Operator as supporting its local area reliability based on its assessment of its Operational Planning Analysis." TOP-001 R13 also says "...within any Transmission Operator Area..." Does the drafting team mean within that particular TOP's area? It would be clearer if it said "...within its area..." If they really do mean another TOP's area, that is unrealistic. It could imply that we need to have info for TOP in Florida. TOP-001 R8 & TOP-002 R2 - When referencing SOLs both say something like "SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability..." National Grid suggests deleting "...which, while not IROLs..."
Response: Requirement 13 – This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Requirement 8 - The wording "while not IROLs" was inserted to make clear that not all limits have adverse reliability impacts, but that some limits that do not have reliability impacts can still be held to a higher standard of operations - as long as those limits are identified. An SOL that has adverse reliability impacts is by definition an IROL. Requirement R8 says that if it isn't an IROL and you want the limit to be controlled in the same way as an IROL, then tell the Reliability Coordinator which limits you want. [Note what all this means –when running its planning and/or operating analysis, the Reliability Coordinator does not find the said limit as causing any BES problems – thus the Reliability Coordinator is not concerned with the said limit. The Transmission Operator however, wants, or is required by some other authority, to treat the said limit as if that limit had BES implications. Such information must be conveyed by the Transmission Operator to the Reliability Coordinator.] Thus, inserting the proposed text will not accomplish the intent of the requirement. No change made.		
Catherine Koch	No	R1 - The addition of the term "identified" does not completely answer the question of who needs to identify the communication as a Reliability Directive. Simply adding the term means that it might be interpreted to mean that that the entity receiving a communication from a Transmission Operator might need to identify the communication as a Reliability Directive from its content and context. The following formulation is more clear: "Each Balancing Authority ... shall comply with each Reliability Directive that its Transmission Operator issues and identifies as a Reliability Directive ..." Given the importance of these requirements, clarity must not be sacrificed for brevity. R8 - The use of the phrase "have been identified" is unnecessary in this requirement. The Transmission

<table>
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<tr><td></td><td></td><td>Operator has an independent obligation to identify these SOLs under the FAC standards. In addition, the phrase “its local area reliability” is ambiguous. If the intent of this term is to address a certain set of SOLs that have more than a purely local effect, then the phrase should be modified to something like “regional reliability” or “that may affect its neighboring Transmission Operator Areas”. The requirement should read “Each Transmission Operator shall inform its Reliability Coordinator of all SOLs that, while not IROLs, support regional reliability based on its assessment of its Operational Planning Analysis” or “Each Transmission Operator shall inform its Reliability Coordinator of all SOLs that, while not IROLs, that may affect its neighboring Transmission Operator Areas based on its assessment of its Operational Planning Analysis.”

M1 - To be consistent with the recommended revisions to R1, the measurement should be revised to read “Each Balancing Authority ... (a) complied with each Reliability Directive that its Transmission Operator issued and identified as a Reliability Directive, ...". Additionally we suggest that the measures provide guidance of how to prove a Reliability Directive was not issued in order to be complete in demonstrating compliance with the requirement. This same suggestion rings through all the measures.M2 - This measurement duplicates a portion of M1.</td></tr>
<tr><td colspan="3">Response: <u>Requirement 1 & Measure M1–</u> The SDT does not agree that the suggested change adds any clarity. No change made.

<u>Requirement 8 -</u> Technically you are correct that the phrase is not needed. However, in this transitional period when a term is being parsed in a special way, the added words are seen (in this case) to be helpful. The words were crafted to mean “local issues.” An outage affecting the White House would not be an impact on the BES but “locally” it would be unacceptable; thus a limit that impacted the White House would be identified by the DC Transmission Operator to the Reliability Coordinator as a special case SOL that must be respected in the same way an IROL is handled. Thus Requirement R8 does mean local and does not refer to impact on others. Note inter-area impacts would be more likely identified by the Reliability Coordinator than the Transmission Operator since the Reliability Coordinator has more intelligence on surrounding areas. No change made.</td></tr>
<tr><td>Jason Shaver</td><td>No</td><td>Requirements #1 & 2

ATC supports Requirements 1 and 2 if the definition of Reliability Directive, as provided in TOP-001-2, is not modified. Any change to the proposed definition of Reliability Directive will require us to reevaluate our position.

Requirement #3

Issue 1: ATC is concerned with the wording of Requirement 3 because it blends real time Emergencies situations with issues or concerns that are identified in Operational Planning Analysis for next day, week, month or year. Definitions: “Emergency” and “Operational Planning Analysis”: Emergency: “Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the BES” Operational Planning Analysis: “An analysis of the expected system condition for the next day’s</td></tr>
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Organization	Yes or No	Question 1 Comment
		operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generation outages, equipment limitations, etc.).” If an Emergency by definition requires automatic or immediate manual action then there would be few if ever a situation in which a next day study would require either automatic or immediate manual action. What reliability objective is the SDT attempting to achieve when combining these two distinct situations into one requirement? Because of this observation ATC believes that the language about anticipated Emergency and Operational Planning Analysis should be deleted. If the SDT does not believe that these deletions are necessary then we request that the SDT provide additional clarify for the phrase “anticipated Emergency”. Supporting TOP Standard:TOP-002-3 addresses the need for a TOP to perform an Operational Planning Analysis and when appropriate to develop a plan based on those results. That plan must be communication to Registered Entities that have to perform an action. *(See ATC’s Comments to TOP-002)* Because TOP addresses next day studies we believe that there is no need for this requirement to also cover Operational Planning Analysis. Clarifying questions: Does the Operational Planning Analysis have to be performed by the TOP itself? (Situation: Currently MISO does a next day study for its footprint. Could that qualify as an Operations Planning Analysis being performed, or does each TOP have to perform its own next day study.) Requirement 3: “... based on its assessment of its Operational Planning Analysis. ”Issue 2: When is notification required to take place? ATC believes that the primary responsibility of the system operator is to address the actual (real-time) Emergency and then when appropriate follow up with the RC and other TOP’s. The only exception is when the TOP has to issue a Reliability Directive which would be issued in response to the situation. Requirement 5: ATC believes that the second sentence should be deleted because all it is attempting to do is provide examples. The first sentence provides enough clarity, so that the second sentence is not needed and may result in more confusion. Requirement 6: Issue 1: Who qualifies as an “affected entity”? If the entity is not registered with NERC how can NERC verify that coordination took place? Does this mean that a TOP, BA and GOP would have to contact customers if the planned outage could affect them? How affected does an entity have to be in order to trigger coordination? Measure 6 states that the TOP, BA and GOP must coordinated “among impacted reliability entities” but there does not exist a definition of “reliability entities”. This standard should clearly set the expectations as to who does the TOP, BA and GOP have to coordinate with and not

Organization	Yes or No	Question 1 Comment
		make the requirement so broad to allow questions about who was involved in the coordination. Issue 2: It is not clear as to when a planned outage of telemetering and control equipment and associated communication channels has to be coordinated. Requirement 7: ATC believes that the term “outside” is not clear and that the SDT should either define the term or use a more appropriate term. Suggested Modification: Modification to R7: “Each TOP shall not “exceed” an identified IROL...” Requirement 8: ATC raised a question on Requirement 3 asking if each TOP has to perform its own Operations Planning Analysis. Based on the answer to that question this requirement may need to be deleted. If an Operations Planning Analysis can be performed by the RC then there would be no need for the TOP to contact the RC about the results of their own study. We believe that Requirement 2 of TOP-002-3 covers Operational Planning Analysis so there is no need to have a duplicate requirement.ATC is unclear as to what this requirement is attempting to achieve. Is this requirement simply saying that the TOP has to share their system operating limits with the RC? If that is the case we believe that the requirement should be rewritten to provide that specific clarity. Suggested Modification: The TOP shall inform the RC of all BES System Operating Limits (SOLs) that support local area reliability. Requirement 9: Issue 1: The proposed requirement is too restrictive because it prevents the TOP from applying loss of life assumption on its equipment. We believe that entities should be able to determine when exceeding equipment limits is appropriate based on the situation and equipment. Suggested Modification:- The TOP may exceed (real-time) a SOL for a continuous duration of 30 minutes. In addition we believe that the TOP should be allowed to use the IROL Tv concept to allow an SOL to be exceeded for a continuous duration of greater than 30 minutes if they notify the RC of the longer SOL Tv. Requirement 10: It is not clear as to when the notifications must take place. Would notifying the RC following the exceedance of the IROL or SOL be okay, or, must the TOP contact the RC prior to taking action in order to be compliant with this requirement? Requirement 12:

Organization	Yes or No	Question 1 Comment
		ATC believes that this requirement is unnecessary because it is only saying that a TOP has to know what is going on with its system. In order to be compliant with the other requirements in this standard a TOP understands that by default they must monitor as appropriate its system. The challenge this requirement introduces is that it is so broad that demonstration of compliance is overly burdensome. In addition this requirement is unclear as to what and how often the TOP has to monitor, or have access to information to demonstrate compliance. Questions: • If a TOP has a 4 second scan rate for EMS data and if a single data scan is missed or an error occurs at a single point does this mean that the TOP is non-compliant? • If an entity uses information on a RC website about planned outages and for some time that system is unavailable for any length of time will the TOP be non-compliant because they don't have access to information? • What does the requirement mean by the phrase "conditions and Facilities"? • Does this mean that the ROP has to monitor breaker statues, switch statues, transformer temperatures, wind conditions and ambient temperatures? • Proposed suggestion: ATC believes that this requirement should be deleted. Requirement 13: This requirement will reduce reliability because it will force TOP's to use the smallest base case model to perform its Operational Planning Analysis. We believe our statement is accurate because it requires the TOP to have an EMS model that matches the Operational Planning Analysis model. So if an entity performs off-line studies (non EMS studies) that use the Eastern interconnection then they must also monitor or have accession to information for the Eastern Interconnection. Since access to all if information is highly unlike or unnecessary to gather the TOP will have to use the model contained in their EMS to perform Operational Planning Analysis. Although this may not necessary be a bad thing a TOP will loss the benefits of using the larger model to perform Operational Planning Analysis. If the RC performs the Operational Planning Analysis then by this requirement does the TOP have to monitor everything in the RC's Operational Planning Analysis model? Suggested Modification: ATC believes that this requirement should be deleted.

Response: "Reliability Directive" is not meant to equate to urgency of a situation; rather, it is meant to equate to the authority placed on a particular action. An urgent situation can be handled without using a NERC Reliability Directive. However, an entity that is not following a Transmission Operator's request or is debating the request can be "made to" to cut off debate and respond as requested by the simple act of the Transmission Operator identifying the request as a Reliability Directive. The requirement views Reliability Directive as a tool, not as a definition of a condition. The use of the Reliability Directive tool is left to the

Organization	Yes or No	Question 1 Comment
System Operator. The exact words needed to affect a Reliability Directive are viewed as an administrative detail not needed in the requirement. To mandate the phraseology would raise the text to the same level as an act to relieve the condition itself. No change made. Requirement 3 – Issue 1: First, Requirement R3 only refers to the assessment of the OPA. The SDT offers what the words were meant to convey: A Transmission Operator is mandated to contact its Reliability Coordinator about System conditions shown in the OPA that will cause the Transmission Operator to initiate Emergency procedures, or may cause the Transmission Operator to initiate Emergency procedures. Requirement R3 extends that contact to other Transmission Operators that either were identified in the OPA as being affected or the Transmission Operator knows are being affected. The wording is crafted to eliminate the possibility that an auditor would find the TOP non-compliant when another Transmission Operator is not previously identified in any study or any procedure. The words state that if you 'know or expect' impacts on someone, then you must contact them to prepare them for the conditions; but if you don't know or expect an entity to be affected, then the requirement does not apply. Requirement 3 links all of the prior conditions to the OPA. That is intended to provide an explicit measure and to mitigate the worry that Requirement R3 applies to any and all impacts. To delete the language about "anticipation" would change the requirement from a requirement that uses an OPA as a reference point, to a requirement that has no reference point. As written, the Transmission Operator can document what it "anticipated." As ATC proposes, the Transmission Operator must satisfy an auditor's subjective view of "anticipate". No change made. There is no requirement that the Transmission Operator do the OPA. The only requirement is that the OPA be performed if the other requirements (e.g., impact on others) can be carried out. No change made. There is no requirement on timing. The requirement is written to accommodate ATC's concern that real-time actions are more important than procedural mandates. The ATC question seems to be requesting the requirement be converted into an administrative procedure. There is no one correct time period to inform others. The requirement is written to recognize that conditions not rules must dictate the response. The Transmission Operator would only be hurting itself if it did not tell others that the Transmission Operator needed them to relieve a problem. If the impact took down the System, the Transmission Operator as well as its neighbor would be hurt. No change made. Requirement 5 – The SDT worded this requirement to comply with a FERC Order 693 directive. No change made. Requirement 6 – Issue 1: The SDT has revised the wording of the requirement to address your comment as well as those of others. Issue 2: planned = any time ahead of fact. No change made. **R6**. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities. Requirement 7 - The term "outside" was used to recognize that there are both upper and lower limits. No change made. Requirement 8 - The ATC suggestion that the Reliability Coordinator, not the Transmission Operator, do the OPA would impose a regional control of Facilities. Today, Transmission Operator s plan, commit, and operate their Facilities for their regulatory defined areas. Those "local" plans are fed to the Reliability Coordinator, which has the right to adjust the local plans based on wide-area considerations. The current Industry approach incorporates local reliability margins. That process is much different than the one ATC is proposing. The ATC proposal would in effect impose the Reliability Coordinator's reliability perspective on all local areas (now the Reliability Coordinator imposes its control over the performance – actual and expected-- of the areas not over the commitment or local margins). The ATC model of total Reliability Coordinator control is not prohibited by the current requirement, but it does not mandate the ATC model. Requirement R3 says nothing about SOLs; Requirement R3 merely requires the Transmission Operator to share advanced warning information (warnings		

Organization	Yes or No	Question 1 Comment
obtained via the OPA) with its Reliability Coordinator. That does not mean the Transmission Operator need not share information that it obtains normally for from other sources. It just says if you predict an emergency based on the OPA, then give others a "heads-up." No change made. Requirement 9 - The debate around SOLs centers on some people's conception that there is one and only one "limit." There is another perspective that forms the basis of this standard and that is both IROLS and SOLs can be a series of values: A lower value that can be used forever, and higher values that can be sustained for shorter time durations. Requirement R9 is only "too prescriptive" if the former concept (of one limit) is used. Requirement R9 is not prescriptive at all. If the Transmission Operator has only one limit, then that value must be used. But if the Transmission Operator has a series of curves, Requirement R9 does not preclude switching magnitude limits from one value to another (and of course switching T_v s from one value to another). However, if the Transmission Operator places a magnitude and a duration on the limit-set, then that limit set must be respected. If ATC uses a 500 MW continuous rating than as long as the flow is 500 MW or less there is not issue. But if the flow exceeds 500 MW, then ATC would either change the limit-set or correct the flow. It must be understood that the Transmission Operator itself has decided (via Requirement R8) that it wants the Reliability Coordinator to handle this particular limit in the same way that the Reliability Coordinator handles IROLs. Why would a Transmission Operator designate a Facility in Requirement R8 and then want to ignore it? No change made. Requirement 10 - There is no requirement on timing. The requirement is written to accommodate ATC's concern that Real-time actions are more important than procedural mandates. The ATC question seems to be requesting the requirement be converted into an administrative procedure. There is no one correct time period to inform others. The requirement is written to recognize that conditions not rules must dictate the response. The Transmission Operator would only be hurting itself if it did not tell others that the Transmission Operator needed them to relieve a problem. If the impact took down the System the Transmission Operator as well as its neighbor would be hurt. No change made. Requirement 12 & 13 – These requirements have been deleted from this project as they have been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
Michael Gammon	No	Requirements R3 & R5 requires TOP's to notify all other "affected" or have an "adverse reliability impact" TOP's of an emergency condition. The terms "affected" and "adverse reliability impact" is a debatable condition and subject to interpretation. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Recommend the requirement be modified to alert other TOP's whenever a TOP in an emergency condition becomes aware of operating conditions that would result in exceeding an SOL or IROL operating limits under N-1 contingency conditions for other TOP facilities. Modifications for these two requirements will result in subsequent changes to the Measures and VSL's for requirements R3 & R5.
Response: Requirement 3 - Requirement R3 is written as an advanced warning and is centered on the OPA results. Requirement R3 is about forecasted (OPA) "expectations". If the Operational plans 'forecast' that the next day's operation will (or is likely) to result in Emergency operations, Requirement R3 says to tell the Reliability Coordinator and the other Transmission Operator s who are explicitly shown to be involved (e.g., they may be needed to carry out a part of the Emergency Operating procedures – such entities are "known" to be involved). On the other hand, there may be "indications" that other Transmission Operators may or may not be involved. Since such an evaluation is indeed subjective (i.e., based on the Transmission Operator's perspective), the requirement is written to bias the Transmission Operator to informing the "expected to be affected" Transmission Operators. You are correct that this part of the requirement is problematic for auditors who are seeking to punish a Transmission Operator. But the standard is not written for punishment purposes, it is written to drive proper actions. The		

Organization	Yes or No	Question 1 Comment
proper action is "when in doubt tell the other party." An auditor cannot (and should not attempt to) measure such marginal/subjective conditions. The SDT believes the words are consistent with NERC's position to write standards that support reliability. No change made. Requirement 5 - Requirement R5 is written as an implementation (of Emergency Operating Procedures) requirement. Requirement R5 is about real-time expectations. If a Transmission Operator knows that its Emergency operations will adversely impact another Transmission Operator in Real-time, then that Transmission Operator is required to inform the latter entity. As with Requirement R3, there is a reliability objective and there is a measureable event. There is also subjectivity in categorizing the "intent." If a Transmission Operator states in its logs or other documents that act X will impact Transmission Operator "A," then that Transmission Operator "knows" and is therefore obligated to follow up; likewise, if a Transmission Operator in its logs or other documentation states that act Y is likely to impact Transmission Operator 'A," then that Transmission Operator is obligated to follow up. A Transmission Operator can supply documents to prove that it followed up. Proving a negative is not expected by this requirement. No change made.		
Leland McMillan	Yes	NorthWestern Energy appreciates this chance to comment. NorthWestern supports the definition of "Reliability Directive" as indicated in the Definitions section. R13 could be clarified to specify the exact types of information about conditions and facilities identified that the entity must have access to. Also, NorthWestern seeks clarification as to why the requirement mandates that the TOP shall have this information "within any Transmission Operator Area"? Perhaps the intent of the requirement is geared towards TOPs obtaining operating information pertaining to their own TOP area, regardless of which TOP area it is actually physically located in? NorthWestern requests that the drafting team consider flexibility in the implementation timelines of this standard. Compliance with this standard might require Transmission Operators to acquire/arrange for Operational Analysis and planning simulation tools not currently required by any FERC approved standards.
Response: Requirement 13 - This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities. Regarding the data -- the requirement as written is linked to the respective Transmission Operator's Operational Planning Analysis process. If the respective Transmission Operator requires a piece of data for that analysis, then Requirement R12 mandates that the Transmission Operator get information about the item in question. To mandate every item would either be too much for some Transmission Operators and too little for others. There is no one analysis format that was found to fit all Transmission Operators. Addressing the FERC Order with a minimum list would violate FERC's other requirement that NERC standards not reflect minimum common denominators. This requirement is designed to require Transmission Operators to follow up on any items that are highlighted in the Transmission Operator's plans. If the operational plan points to a situation (e.g., a Facility in another area) then the Transmission Operator must make accommodations to obtain information about that facility. That does not mean that the Transmission Operator must have an RTU feed from the Facility, but it does mean that the Transmission Operator must make arrangements to get the information/communications somehow (e.g., having the neighbor report a line flow periodically, or report when the flow exceeds some predetermined value…). The context of the requirement is that if a Transmission Operator needs information to do its reliability studies then that		

Organization	Yes or No	Question 1 Comment
Transmission Operator should get the information even if that information is from a non-adjacent entity. Take for example a 3000 MW DC line between two Interconnections. That line could carry a 3000 MW interchange schedule. The loss of that line could affect a third party Transmission Operator with an impact greater than the Transmission Operator's largest Contingency. In such a case, it would be necessary for all parties to agree to how much interchange will be allowed. Moreover the non-adjacent Transmission Operator may want to be informed of what the loading of the DC line is so as to maintain the security of its own Transmission Operator area. This example would also involve Reliability Coordinators, but the point is that if there is a need than the Transmission Operator is obligated to get sufficient information (not metering just information – like a phone call) to ensure that the System is reliable. No change made. The requirements are written from the perspective of the Transmission Operator and "its" tools; not from the perspective of an auditor and what the audit believes is the right tool. The requirements do not impose common tools or data or lists (see comments to others who want such lists ostensibly to protect themselves). The requirements are written to recognize that a Transmission Operator may be as small as one line or as large as half an Interconnection. The tools and data and procedures must of necessity be different and these requirements respect that diversity. No change made.		
Northeast Power Coordinating Council	Yes	In R9, to clarify the requirement to operate below a System Operating Limit (SOL), "outside" should be replaced with the wording "at or above".
Response: The term "outside" was used to recognize that there are both upper and lower limits. To insert "at or above" could be construed by some people as not including "at or above." No change made.		
Darryl Curtis	Yes	
Dan Rochester	Yes	We applaud the SDT of its positive response to our previous comments regarding the lack of monitoring of and requirement to operate within SOLs. Although the revisions do not go all the way to ensuring operating within all SOLs, and mitigating exceedances as they occur, the revised standard goes a long way in meeting that general intent. We agree with all the changes to the Time Horizons, Measures, data retention and compliance elements (VRFs and VSLs).
Kasia Mihalchuk	Yes	
PacifiCorp	Yes	
Response: Thank you for your support		
Western Electricity Coordinating Council		Under R1 of the standard the word "identified" is used to describe a specific type of Reliability Directive issued by the Transmission Operator. Who performs the work or makes the identification of an "identified" reliability directive? Why under R2 is the classification not carried on to describe the RC directive such as "of its inability to

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>perform an IDENTIFIED Reliability Directive”?</td></tr>
<tr><td colspan="3">Response: As written, the Transmission Operator would “identify” an action as a Reliability Directive. No change made.

The SDT has revised Requirement R2 as suggested:

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]</td></tr>
<tr><td>Randi Woodward</td><td></td><td>Minnesota Power does not have any comments at this time.</td></tr>
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2. TOP-002-3: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: The SDT edited the text box for the rationale for Requirement R1 and adjusted the wording for Requirement R3 and M3 based on industry comments to provide additional clarity and to make the intent of the SDT clear.

R3. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

M3. Each Transmission Operator shall have evidence that it notified all ~~reliability~~ registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

Organization	Yes or No	Question 2 Comment
Public Service Enterprise Group Companies	No	The Rational to R1 should add language to clarify that in some circumstances the failure or unavailability of the usual tools may result in the inability to perform a complete and comprehensive analysis. Therefore the words "to the extent practicable" should be added (see below) in the last sentence after the word "able."Rationale for Requirement R1:By definition, Operational Planning Analysis includes Contingency analysis. By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have analysis tools or procedures to perform the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, if tools are used, the Transmission Operator must be able to the extent practicable to complete the analysis even if those tools are not available.
Response: What is required is to have an effective Operational Planning Analysis. How that is provided is up to the entity. Introducing phrases and qualifiers such as "to the extent practicable" would result in something that cannot be measured. No change made.		
Bonneville Power Administration	No	R2 Although an entity does not plan to operate above the SOL, a contingency may cause an short SOL excursion until planned mitigation action is completed within the Tv (allowable violation time limit). Non-electrical people could get confused by this distinction. Suggest clarifying SOL as intended to be path loading limits and/or local area transmission service support limits, (the BES is a big system with lots of ratings, it can also mean voltage limits in addition to line and path limits).
Response: T_v is defined only for Interconnection Reliability Operating Limits (IROL). While the SDT agrees with your statements that short excursions may occur within an applicable time which respects Equipment Ratings, that time may vary significantly from one SOL to another. The suggestion to clarify SOL as intended to be path loading limits or local area Transmission service support limits is problematic as those terms are not universal in use nor are they defined. Requirement		

Organization	Yes or No	Question 2 Comment
R2 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). No change made.		
SERC OC Standards Review Group	No	In R2 and M2, what is the meaning of "local area reliability" and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word "supporting' could be replaced by the phrase "necessary for".
Response: IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Reliability Coordinator or Transmission Operator has determined to be important to supporting reliability in a local area. No change made.		
Southern Company Transmission	No	Southern's comments: The current NERC Glossary definition of Operations Planning Analysis does not explicitly include contingency analysis. Unless the SDT is modifying the definition of Operations Planning Analysis to include contingency analysis, we recommend that R1 be re-expanded to include the expectation of performing contingency analysis. Regarding R2 and M2, a TOp should not plan to operate beyond any SOL limit - regular or one that "is supporting local reliability." Otherwise, why should it be classified as an SOL? SERC's comments: Southern participated in developing these comments and support them. In R2 and M2, what is the meaning of "local area reliability" and could that mean all SOLs? We believe the team intended to have a definite subset of SOLs. Perhaps the word "supporting' could be replaced by the phrase "necessary for".
Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue: R2 and M2**:** IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Reliability Coordinator or Transmission Operator has determined to be important to supporting reliability in a local area. No change made. SERC's comments: Knowing SOLs is important for situational awareness (know where you are and where you expect to operate) and for determining whether Adverse Reliability Impacts may result from exceeding them. If such an adverse impact is predicted, there is potential that the SOL is indeed an IROL. If it does		

Organization	Yes or No	Question 2 Comment
not meet the qualifiers as an IROL, but it is important to a local area, the Transmission Operator (or a Reliability Coordinator, for that matter) may designate such an SOL for the Reliability Coordinator to include in the limits that must be honored and mitigated as soon as possible, but no longer than 30 minutes. No change made.		
MRO's NERC Standards Review Subcommittee	No	The rationale box needs to be clarified. If the drafting team meant for entities to have a primary set of tools / procedures and backup set as well, please clarify that. “By definition, Operation Planning Analysis includes Contingency analysis” is not accurate. The definition in the Glossary of Terms mentions nothing of contingency analysis. It mentions known transmission and generation facility outages, but that has nothing to do with contingency analysis, which includes a study of unknown events to occur on current system conditions. Therefore, the requirement should read “Each Transmission Operator shall have an Operational Planning Analysis that incorporates potential single contingency events.” Is “plan” in requirement R2 a noun or verb? It appears to read as if it is a verb, which implies no documented action would be necessary. If intended, it should read “Each Transmission Operator shall develop a plan....” This flows much better with what the intent of R2 is trying to say.
Terry Harbour	No	The rationale box needs to be clarified. If the drafting team meant for entities to have a primary set of tools / procedures and backup set as well, please clarify that. “By definition, Operation Planning Analysis includes Contingency analysis” is not accurate. The definition in the Glossary of Terms mentions nothing of contingency analysis. It mentions known transmission and generation facility outages, but that has nothing to do with contingency analysis, which includes a study of unknown events to occur on current system conditions. Therefore, the requirement should read “Each Transmission Operator shall have an Operational Planning Analysis that incorporates potential single contingency events.” Is “plan” in requirement R2 a noun or verb? It appears to read as if it is a verb, which implies no documented action would be necessary. If intended, it should read “Each Transmission Operator shall develop a plan....”
Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. ‘Plan’ in Requirement R2 is a verb. It is the process of putting together the operations plan for whatever timeframe is applicable. Part of that process includes the performance of an Operational Planning Analysis. No change made.		
Joylyn Faust	No	The proposed standard which indicates the TO shall “notify” reliability entities as to “their role” appears to be bolstering the authority of the TO. During real time events the TO should have authority to issue directives, however on a planned basis TOs should coordinate, not dictate the role of the entities. On a planned basis,

Organization	Yes or No	Question 2 Comment
		input from the involved entities will result in a more reliable system.
Response: The requirement, following the coordination required to develop an operating plan, is to notify the entities that have roles in the operating plan, and what those roles are. For example, those entities may have actions to perform, or they may have Facilities that will be impacted by actions taken by others. Reliability Standard TOP-002-3 pertains to Operations Planning. The execution of the operations plans developed within the requirements of TOP-002-3 is covered in other standards. The SDT agrees that input from the involved entities will result in a more reliable System, but once that input has been received and a plan has been put into place, those entities with roles in the plan must be notified as to what are those roles. No change made.		
Jon Kapitz	No	R2. Each Transmission Operator shall plan to preclude operating in excess of those Interconnection Reliability Operating Limits (IROLs) and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. Xcel Energy believes this requirement is confusing as written. It appears to want to include all SOLs. If so, why not just state as such? It could be simply stated as "...IROLS and SOLS..." R3. Each Transmission Operator shall notify all reliability entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). Xcel Energy believes this should be limited to just entities within the TOP's own area.
Response: IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Transmission Operator has determined to be important to supporting reliability in a local area. Requirement R2 allows a Transmission Operator to choose whatever parochial definition it desires, including no SOLs as well as all SOLs. However, the standard requires neither any SOL nor every SOL. Such an approach seems to ensure the integrity of the BES (since all IROLS are covered) as well as the local sensitivities of the Transmission Operator (i.e., identified SOLs). No change made. Knowing SOLs is important for situational awareness (know where you are and where you expect to operate) and for determining whether Adverse Reliability Impacts may result from exceeding them. If such an adverse impact is predicted, there is potential that the SOL is indeed an IROL. If it does not meet the qualifiers as an IROL, but it is important to a local area, the Transmission Operator may designate such an SOL for the Reliability Coordinator to include in the limits that must be honored and mitigated as soon as possible, but no longer than 30 minutes. No change made.		
Howard Rulf	No	Rationale for Requirement R1: Operational Planning Analysis does not include Contingency analysis "by definition". "Contingency analysis" does not appear in the definition of Operational Planning Analysis. R2: Since any SOL is to "ensure operation within acceptable reliability criteria" this requirement requires that the TOP include all SOLs in their "plan". R3: When is this notification to take place? Since this analysis starts taking place as much as 12 months in

Organization	Yes or No	Question 2 Comment
		advance, as the plan changes over time there could be multiple conflicting notifications.
Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. R2 - IROLs are the subset of SOLs that "…could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages." The remaining SOLs are those that relate to local areas of the BES. An Operational Planning Analysis is to respect all SOLs, but the Real-time operations requirement to mitigate applies only to IROLs and those specially designated SOLs that the Reliability Coordinator or Transmission Operator has determined to be important to supporting reliability in a local area. Knowing SOLs is important for situational awareness (know where you are and where you expect to operate) and for determining whether Adverse Reliability Impacts may result from exceeding them. If such an adverse impact is predicted, there is potential that the SOL is indeed an IROL. If it does not meet the qualifiers as an IROL, but it is important to a local area, the Transmission Operator (or a Reliability Coordinator, for that matter) may designate such an SOL for the Reliability Coordinator to include in the limits that must be honored and mitigated as soon as possible, but no longer than 30 minutes. No change made. R3 – After the Transmission Operator runs an Operational Planning Analysis and determines another entity as having a role in their plan and before the affected entity has to take action, they should notify the affected entity. No change made.		
RoLynda Shumpert	No	In "Consideration of Comments on First Draft of Revised TOP Standards Real-Time Operations - Project 2007-03," p77, #6 response, March 26, 2009, it was stated that "reliability entities" is not a defined term. In addition, in "Consideration of Comments on Second Draft of Standards for Real-Time Operations (Project 2007-03)," pp 64-65, August 25, 2009, a response is given to Xcel Energy's comment that the phrase reliability entities needs definition that "reliability entities are the entities certified by NERC as such." SCE&G believes that it is unclear what is meant by "certified by NERC as such" and would appreciate that these entities be spelled out as it relates to these Standards. It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: -Reliability entities: -The SDT has changed the wording to 'registered entities.' **R3**. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). The SDT has checked all the references and made corrections as needed.		
Greg Rowland	No	R2, M2 and R2 VSL - Replace the phrase "supporting its local area reliability" with the phrase "having an Adverse Reliability Impact". This adds clarity regarding which SOLs must be addressed in the TOP's plan. R3 VSL - The mixing of numbers with percentages and the phrase "whichever is less" in these VSLs is

Organization	Yes or No	Question 2 Comment
		confusing. For example, if there are four affected entities, and the TOP does not notify one of the four, then that is one entity, or 25% of the total. What does "whichever is less" mean? Is that a Lower or Severe violation? Conversely, if there is only one affected entity and the TOP does not notify that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation?
Response: R2, M2, and R2 VSL: Replacing the phrase "supporting its local area reliability" with the phase "having an Adverse Reliability Impact" would be inappropriate because the definition of Adverse Reliability Impact clearly indicates impact to a widespread area of the BES, not just a local area. No change made. R3 VSL: The mixing of numbers and percentages is standard verbiage for VSLs. It is designed to allow for size differences in applicable functional entities. 'Whichever is less' means simply that you use the option that is less numerically. No change made.		
Michael Lombardi	No	The rationale box for Requirement R1, indicates that TOP must be able to complete analysis even if the tools that are used are not available. It is not clear how contingency analysis would be performed if study tools are not available. What if day ahead study tools are part of an Energy Management System (EMS) which is a high reliability redundant system with an independent system at a back up facility? Is the rational box verbiage suggesting one would need to postulate the loss of a redundant EMS as well as its back up facility? Please clarify what is to be accomplished pursuant with R1. The term "Operational Planning Analysis", is capitalized to identify it as a defined term yet the NERC Glossary of Terms (updated 4/20/2010) indicates that the term has not been FERC approved. (See additional write up in Question 1 comment)
Response: What is required is to have an effective Operational Planning Analysis. How that is provided is up to the entity. The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. The following definition is taken from the NERC Glossary of Terms Used in the Reliability Standards: "Operational Planning Analysis: An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." This definition has been approved by the NERC BOT but not yet approved by FERC. NERC BOT approval gives the definition operational authority. No change made.		
Saurabh Saksena	No	TOP-001 R8 & TOP-002 R2 - When referencing SOLs both say something like "SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability...". National Grid suggests deleting "...which, while not IROLs...". ,

Organization	Yes or No	Question 2 Comment
Response: The wording "while not IROLs" was inserted to make clear that not all limits have adverse reliability impacts, but that some limits that do not have reliability impacts can still be held to a higher standard of operations - as long as those limits are identified. An SOL that has adverse reliability impacts is by definition an IROL. Requirement R8 says that if it isn't an IROL and you want the limit to be controlled in the same way as an IROL then tell the Reliability Coordinator which limits you want. [Note what all this means –when running its planning and/or operating analysis, the Reliability Coordinator does not find the said limit as causing any BES problems – thus the Reliability Coordinator is not concerned with the said limit. The Transmission Operator however, wants, or is required by some other authority, to treat the said limit as if that limit had BES implications. Such information must be conveyed by the Transmission Operator to the Reliability Coordinator.] Thus, inserting the proposed text will not accomplish the intent of the requirement. No change made.		
Catherine Koch	No	R1/R2 - The side-bar indicates that Contingency analysis is included Operational Planning Analysis by definition. The definition of Operational Planning Analysis, however, does not discuss or even mention Contingency analysis. Recommend a revision to the definition of Operational Planning Analysis to clarify that such an analysis does include Contingency analysis. R2 - See comments regarding identified SOLs under requirement R8 of TOP-001-2 above.
Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue. R2: See response to comments regarding identified SOLs under requirement R8 of TOP-001-2.		
Jason Shaver	No	Rational Box: The SDT states that by definition Operational Planning Analysis includes Contingency Analysis. ATC does not agree with this statement and therefore we requests that the SDT removed this statement. Operation Planning Analysis: "An analysis of the expected system condition for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generation outages, equipment limitations, etc.)."The definition does not specifically call out contingency analysis but is specific that an Operations Planning Analysis is a next day study which can be performed any time from a day ahead to as much as 12 months ahead. Time Horizon: In TOP-001-2 Requirement 2 the SDT calls on Operations Planning Analysis to be performed and identifies it as either a Same-Day Operations, Real-Time Operations Time Horizon requirement. In TOP-002-3 Requirement 1 the SDT is calling for Operations Planning Analysis to be performed and identifies it as a Operations Planning Time Horizon. ATC finds it very confusing that the SDT is using this defined term in multiple Time Horizons and believes that a single time horizon be used for this term.

Organization	Yes or No	Question 2 Comment
		Requirement 1:If a TOP were to perform an Operations Planning Analysis for TOP-001-2 then what different Operations Planning Analysis would a TOP have to do be in compliance with Requirement 1 of TOP-002-3? Requirement 2: ATC believes that Requirement 2 (TOP-002-3) conflicts with TOP-001-2 Requirement 9. Requirement 9 in TOP-001-2 allows a TOP to exceed an SOL for a continuous duration of 30 minutes but that same allowance is not provided in requirement 2. (Note: see ATC's comment to Question 1 requirement 9.) ATC believes that the same continuous duration time provided in Requirement 9 of TOP-001-2 be allowed in Requirement 2. Requirement 3: ATC believes that additional clarity is needed around the use of the term "role". We believe that this requirement is calling for TOP's to contact other Registered Entities if they have an "action" to perform in the plan. Is ATC's understanding of the term "role" consistent with the SDT's understanding? A TC also believes that the phrase "reliability entities" should be replaced with Registered Entities.

Response: The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue.

Time Horizon: Time Horizon refers to the time period for mitigating a violation to the requirement, not an operating timeframe. TOP-001-2, Requirement R2 does not address Operational Planning Analysis. Requirement R3 does mention Operational Planning Analysis and does apply to the Same Day Operations and Real-Time Operations Time Horizons. TOP-002-3 pertains to Operations Planning, while TOP-001-2 pertains to multiple Time Horizons. No change made.

Requirement 1: If the Operational Planning Analysis performed includes all the relevant expected conditions, it may be appropriate for a next-day analysis, same-day analysis, or Real-time analysis. However, if any actual System conditions differ from the assessed conditions, the entity must decide whether the analysis continues to cover the potential reliability impacts. If not, then the analysis should be updated. No change made.

Requirement 2: TOP-002-3, Requirement R2 pertains to Operations Planning. TOP-001-2, Requirement R9 pertains to Real-time Operations. The assessment of an Operational Planning Analysis in Operations Planning may "predict" that an SOL or IROL will be exceeded, but it does not predict a duration of that exceedence. In Real-time Operations, the entity must be taking mitigation actions whenever an exceedence is identified. If that exceedence cannot be mitigated within 30 minutes, then the exceedence becomes a violation. No change made.

Requirement 3: The requirement, following the coordination required to develop an operating plan, is to notify the entities that have roles in the operating plan, and what those roles are. For example, those entities may have actions to perform, or they may have Facilities that will be impacted by actions taken by others. No change made.

Reliability entities: The SDT has changed the wording to 'registered entities'.

R3. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

Organization	Yes or No	Question 2 Comment
Jonathan Appelbaum	Yes	“Operational Planning Analysis” is not a defined term in the NERC Glossary and a proposed definition is not included in the Draft Standard. TOP-001 and TOP-002 have capitalized the term indicating a definition. TOP-002 information box says “by definition Operational Planning Analysis includes Contingency Analysis.”
Response: The following definition is taken from the NERC Glossary of Terms Used in the Reliability Standards: “Operational Planning Analysis: An analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).” This definition has been approved by the NERC BOT but not yet approved by FERC. NERC BOT approval gives the definition operational authority. No change made. The SDT agrees that the definition of Operational Planning Analysis does not explicitly contain Contingency analysis. However, the SDT believes that the list of items contained in the definition (load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)) covers all of the issues that need to be included in the desired analysis. The SDT has changed the wording in the rationale box to clarify this issue.		
Dan Rochester	Yes	Again, we applaud the SDT of its positive response to our previous comments regarding the lack of consideration to SOLs in operational planning. Although the revisions do not go all the way to ensuring TOPs plan their operations to respect all SOLs, the revised standard goes a long way in meeting that general intent. We agree with all the changes to the Time Horizons, Measures, data retention and compliance elements (VRFs and VSLs).
IRC Standards Review Committee	Yes	No comment at this time. (The YES box was inadvertently checked, which we are unable to de-select)
Northeast Power Coordinating Council	Yes	
Michael Gammon	Yes	
E.ON U.S.	Yes	
Midwest ISO Standards Collaborators	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 2 Comment
FirstEnergy	Yes	
Dominion	Yes	
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	Yes	
Kasia Mihalchuk	Yes	
Leland McMillan	Yes	
Richard Kafka	Yes	
Response: Thank you for your support.		
Randi Woodward		Minnesota Power does not have any comments at this time.

3. TOP-003-1: Do you agree with the changes made to this standard? This includes all aspects of this standard – requirements, measures, data retention, VRF, Time Horizon, and VSL. If not, please supply specific reasons why you do not agree with the changes made.

Summary Consideration: No comments were received that required contextual changes to the requirements. Some semantic changes were made for additional clarity to Requirement R1 and the Measures.

R1. Each Transmission Operator and Balancing Authority shall ~~have~~ create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

R1, Part 1.1, bullet #1 - Long term outages of Bulk Electric System (BES) equipment~~, as specified by the Transmission Operator or Balancing Authority~~

R1, Part 1.1, bullet #2 - Operating parameters for equipment of the BES and at voltage levels lower than the BES~~Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority~~

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

M5. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

Organization	Yes or No	Question 3 Comment
SERC OC Standards Review	No	We believe that R5 is redundant to R4 if the Transmission Operator is added to R4.

Organization	Yes or No	Question 3 Comment
Group		
Dominion	No	It is not clear how the data provision obligations of BAs under requirement R4 are different from their obligations under R5. We therefore suggest that TOP be added to R4 and that R5 be removed.
Response: The SDT felt it appropriate to distinguish the individual aspects of the data requirements. Requirement R1 notes that data requirements will be established by the Transmission Operator and Balancing Authority. Requirement R2 covers the Transmission Operator's responsibility to make the requirements known. Requirement R3 does the same for Balancing Authorities. Requirement R4 requires that other entities respond accordingly to the requests for data. And Requirement R5 requires the Transmission Operators and Balancing Authorities to share that data with other Transmission Operators and Balancing Authorities that need the data. Clarity in the requirements, especially with regard to specific roles and responsibilities of involved entities was the goal. Layered in this manner, it provides a control for data requests to be made through the Balancing Authority or Transmission Operator for the area, rather than having Transmission Operators or Balancing Authorities requesting data from non-Transmission Operators or non-Balancing Authority entities within another area without also assuring the data was known and provided to the host Transmission Operator or Balancing Authority. This may have been done through other approaches but the SDT chose this approach to achieve the desired clarity. No change made.		
Southern Company Transmission	No	Southern's comments:M4 and M5, there should be allowance for outstanding requests that are still within the deadline as defined in R1.4. SERC's comments: Southern participated in developing these comments and support them We believe that R5 is redundant to R4 if the Transmission Operator is added to R4.
Response: The SDT presumed the meaning was clear that outstanding requests referenced only those which have exceeded the time to respond and agrees that additional clarity is required. Revisions were made to Measures M4 & M5. **M4.** Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4. **M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4. The SDT felt it appropriate to distinguish the individual aspects of the data requirements. Requirement R1 notes that data requirements will be established by the Transmission Operator and Balancing Authority. Requirement R2 covers the Transmission Operator's responsibility to make the requirements known. Requirement R3 does the same for Balancing Authorities. Requirement R4 requires that other entities respond accordingly to the requests for data. And Requirement R5 requires the Transmission Operators and Balancing Authorities to share that data with other Transmission Operators and Balancing Authorities		

Organization	Yes or No	Question 3 Comment
that need the data. Clarity in the requirements, especially with regard to specific roles and responsibilities of involved entities was the goal. Layered in this manner, it provides a control for data requests to be made through the Balancing Authority or Transmission Operator for the area, rather than having Transmission Operators or Balancing Authorities requesting data from non-Transmission Operators or non-Balancing Authority entities within another area without also assuring the data was known and provided to the host Transmission Operator or Balancing Authority. This may have been done through other approaches but the SDT chose this approach to achieve the desired clarity. No change made.		
MRO's NERC Standards Review Subcommittee	No	Remove “at the discretion of the Transmission Operator or Balancing Authority” in R1-1.1. The TO and BA are the entities creating the specification, which already implies that any needed parameters are at their discretion. Overall clarification seems necessary on this bullet as well (R1-1.1). Why specifically address equipment of voltage levels below BES levels? Does this exclude equipment rated 100 kV and above? Replace “Real-time monitoring” with “Real-time Assessment” as this is an actual term in the NERC Glossary of Terms. This would follow a similar format to the “Operational Planning Analyses”.
Terry Harbour	No	Remove “at the discretion of the Transmission Operator or Balancing Authority” in R1-1.1. The TO and BA are the entities creating the specification, which already implies that any needed parameters are at their discretion. Overall clarification seems necessary on this bullet as well (R1-1.1). Why specifically address equipment of voltage levels below BES levels? Does this exclude equipment rated 100 kV and above? Replace “Real-time monitoring” with “Real-time Assessment” as this is an actual term in the NERC Glossary of Terms. This would follow a similar format to the “Operational Planning Analyses”.
Response: The SDT was careful to be explicit and specifically clear in the requirements. However, the comment does point out an opportunity for additional clarification. **R1, Part 1.1, bullet #1** - Long term outages of Bulk Electric System (BES) equipment~~, as specified by the Transmission Operator or Balancing Authority~~. **R1, Part 1.1, bullet #2** - Operating parameters for equipment of the BES and at voltage levels lower than the BES~~Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority~~. The SDT believes that the wording is correct as stated. No change made.		
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	No	R1.1 - The phrase ‘to be exchanged’ seems to be unnecessary. M2 and M3 - These measures allude to evidence of information actually being distributed, yet some companies make information available to entities through website posting or other public forums. Please

Organization	Yes or No	Question 3 Comment
		include showing proof of availability of information to an entity as an option in these measures. M4 - The last sentence should be revised to match the last sentence of M5. Consider rewording both M4 and M5 as follows: "The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled." The R2 and R3 VSLs have percentage approaches, but the R4 and R5 VSLs are binary, even though there are multiple elements to data specifications referred to in R4 and R5. All four of these requirements should have percentage approaches. Similarly, there are requirements for the RC (in IRO-010) to document data specifications. The associated IRO-010 R1 and R2 VSLs also have a percentage based approach. To be consistent, the TOP-003-2 R4 and R5 VSLs need to be changed to the percentage based approach for consistency.

Response: R1.1 – The SDT does not see that the suggested change adds any additional clarity. No change made.

M2 & M3 – The SDT has revised the measures based on your comments.

> **M2**. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

> **M3**. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4 & M5 – Clarifications have been made to measures M4 and M5.

> **M4.** Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

> **M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.

R2 & R3 VSL – The SDT believes that there is a reliability-based difference to distribution of the specification versus supply of the data and that the VSLs reflect this difference. No change made.

Organization	Yes or No	Question 3 Comment
Style changes.Dan Rochester	No	M5: The last sentence added is in fact a requirement. Measures should not include requirement for “completeness” of the data provision, which is already implicit in R5. The extent to which the data is not fully provided should be assessed and reflected by the VSLs. Suggest to delete this sentence and as desired, expand the VSLs for R5 to make them graded according to the percentage of data not provided.
Response: -Measure M5 was changed due to industry comments. The measure created is a binary one. There are either outstanding (i.e., unfilled or unaddressed) requests for data, or there are not. The SDT can see no additional requirements added to the standard by this measure. No change made to the VSL. **M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.		
Joylyn Faust	No	Poorly worded. According to the proposed standard the TO is supposed to “exchange” data, at its discretion, regarding equipment ratings at voltage levels below the BES. So when our TO demands HVD equipment ratings, what are we to exchange it with? Again, this standard appears to be bolstering the authority of the TO. If the TO can demand information from the DP, then the DP should have access to similar information regarding the TO’s system.
Response:- The standard is enabling the Transmission Operator to meet its reliability obligations. These obligations do not extend to the same degree or scope to the Distribution Provider. Therefore, there is not the same need for data by the Distribution Provider as there is for the Transmission Operator. The standard is appropriately establishing the levels of authority for data gathering as needed for reliability and in keeping with the established functional model. No change made.		
John Fish	No	M4. "The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled." Should be removed The response to the "request for data", or an attestation that no requests have been made, should stand alone as proof of GO/GOP compliance??
Response: -Measure M5 has been changed to address industry comments. **M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.		
Howard Rulf	No	TOP-003-2R1: Nowhere in NERC Standards is a TOP or BA required to perform an Operational Planning Analysis. This requirement applies to data specifications. It does not require Operational Planning Analysis.

Organization	Yes or No	Question 3 Comment
		R1.2: Who mutually agrees to the format? The TOP and BA? A TOP or BA may have scores of different entities with Facilities within their boundaries. Is this requiring data format agreements with scores of other entities? The TOP and BA should be allowed to specify the data format. R4: Please explain what is meant by “satisfy the obligations of the documented specifications for data”. Please rephrase this to something more clearly understandable in the requirement. R5: Consider modifying this requirement so that the data is provided directly where possible. Data received indirectly through other entities is delayed, and there are increased chances of problems in receiving the data.
Response: R1 - This standard addresses data specifications and the obligations to provide and share data, as appropriate, and as needed, to perform reliability analyses for operations planning as required in proposed TOP-002-3. No change made. R1.2 - The requirement does not mandate “format agreements” with anyone. The mutual agreement is between the provider and the requester of the data. In this regard it is reasonable to expect that a standard format will emerge, but it is not required. The SDT believes this approach is the best way to avoid placing unreasonable format requirements into the standard. No change made. R4 – “Satisfy the obligations” means to supply the requested data according to the requirements. The SDT does not see any problem with the present wording and absent any suggested wording does not see any reason for changing the current wording. R5 – The requirement does not tell an entity how to handle data, just what data needs to be delivered. No change made.		
RoLynda Shumpert	No	It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: The SDT will review and correct as needed prior to the next posting.		
Greg Rowland	No	R2 and R3 VSLs - The mixing of numbers with percentages and the phrase “whichever is less” in these VSLs is confusing. For example, if there are four entities, and the TOP or BA does not distribute its data specification to one of the four, then that is one entity, or 25% of the total. What does “whichever is less” mean? Is that a Lower or Severe violation? Conversely, if there is only one entity and the TOP does not notify that entity, then that is one entity or 100% of the total. Is that a Lower or Severe violation?
Response: R2 & R3 VSL – The SDT believes that there is a reliability-based difference to distribution of the specification versus supply of the data and that the VSLs reflect this difference. No change made.		
Randi Woodward	No	Minnesota Power has the following comments for the individual requirements of the proposed Standard TOP-003-2.Requirement 1 o The time horizon doesn’t appear to match the requirement.

Organization	Yes or No	Question 3 Comment
		o The tasks required to accomplish the items listed in sub-requirements R1.1 - R1.4 also fall under the responsibility of a Reliability Coordinator, in addition to the Transmission Operator and Balancing Authority functions that are already listed in this Requirement. o The term “mutually agreeable format” is confusing and needs more definition to eliminate any confusion regarding who is required to agree on the format in sub-requirement 1.2. Requirement 4 o The way this Requirement is currently worded could leave the door open for disparate specifications. As currently written, Registered Entities are obligated to abide by all specifications regardless of feasibility or ability to implement. Minnesota Power requests more clarification regarding what is meant by “satisfy the obligations of the documented specifications for data.” Requirement 5 o The way this Requirement is currently written it could open the door for a liberal interpretation of the Requirement and could result in excessive data requests in the name of “Operational Planning Analysis and Real-time monitoring.” Minnesota Power suggests revising the Requirement to state that the requesting Transmission Operator and/or Balancing Authority must demonstrate a reliability need in its request for data.
Response: Time Horizon refers to the time period for mitigating a violation to the requirement, not an operating timeframe. The SDT has reviewed the current Time Horizons and feels it is appropriate. No change made. Reliability Coordinator responsibilities are covered in other standards. There may be similar data requirements for Reliability Coordinators, but that doesn’t negate the need for such data by the Transmission Operators and Balancing Authorities. Additional requirements for other entities do not conflict with this requirement, which stands on its own. No change made. Mutually agreeable is self-explanatory and is between the requester and the provider of the data. No change made. “…satisfy the obligations of the documented specifications for data…” is clear in that the data, specified by the Transmission Operator or Balancing Authority in the requesting documentation must be provided as requested to satisfy the obligation. The SDT thinks this requirement is clear. No change made. Demonstrating a reliability need for data is unnecessary. There is no expectation that a Transmission Operator or Balancing Authority would request data that is unneeded. There is a burden placed onto the Transmission Operator and Balancing Authority to manage the data requested, and an expectation that data will be used and useful. It is not reasonable to expect that unneeded data will be requested as there is no incentive to make such a request, and some incentive not to do so. No change made.		
Catherine Koch	No	R1 - As indicated in the first full row on page 5 of the document “Resolution of Issues Assigned to Real-time Operations SDT (Project 2007-03)”, FERC staff disagrees with the data specification approach. How does the SDT propose to deal with this disagreement? Given this disagreement and FERC’s current concerns with NERC’s standard approval process, what purpose does continuation of the current approach accomplish? R1.2 - The phrase “mutually agreeable format” may lead to disputes between the TOP and other entities

Organization	Yes or No	Question 3 Comment
		subject to the TOP's data specification. In the event that the entities cannot agree, the TOP's reasonable requirements should trump. R1.4 - There should be language added that requires agreement to proposed deadline by the entity receiving the specification as there could be a need for programming work and it could be foreseen that the deadline indicated can not be reasonably met.
Response: R1 – NERC staff believes, and the SDT concurs, that the data specification approach outlined here and in the proposed IRO standards is a more effective approach to data handling and is working with FERC staff to bring this issue to a satisfactory conclusion. No change made. R1.2 and R1.4 - If there is a disagreement that cannot be handled by the entities involved, the SDT believes that existing conflict resolution agreements would be used to resolve the dispute. No change made.		
Jason Shaver	No	Requirement 1.1: ATC believes that requirement 1.1 is unnecessary and opens up other issues and therefore should be deleted from this standard. Long-term outage information while important is not directly related to EMS data. In addition, information about facilities that operate below 100 kV is beyond FPA 215 and is beyond NERC's jurisdiction.
Response: It is correct that the requirement for data does indeed extend beyond EMS data. This is the intent of the requirement. This data is needed to enable appropriate operations planning for conditions (which real-time EMS scans would not represent) throughout the Operations Planning Horizon, as is the intent of the requirement. Facilities below 100 KV may have material impact to the BES and, as such, are within the scope of the requirement and must, as determined necessary by the host Balancing Authority or Transmission Operator, be included. No change made.		
Michael Gammon	No	Requirement R4 may be troublesome for small Registered Entities to meet the data requirements dictated by larger Registered Entities. The is no recognition of the limitations of data exchange capability with an entity. Recommend requirement R4 be modified to include "within the data exchange capabilities of the recipient of the data specification". Modifications here would result in changes to the Measure and VSL for requirement R4.
Response: It is not anticipated that a data request would be made for data that is not reasonably available. Nonetheless, the concept of a standard in this regard is to assure that data needed for reliable operations is made available, as appropriate. This standard incorporates the ability for Transmission Operators and Balancing Authorities to adjust data requirements to meet the needs of regional areas, while maintaining a standard. The SDT believed this approach superior to one which mandated a one-size-fits-all data requirement, which would result in either insufficient data because the standard was too weak (accommodating various levels of data gathering capabilities), or too stringent in some cases (as potentially described in this comment), thereby creating unreasonable data requests in some cases. The SDT used this approach to enable addressing the concern raised here as would not be possible in the one-size-fits-all approach. No change made.		

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	We commend the drafting team for attempting to manage the evidence in a way that does not require the TOP to get evidence to prove an absence of an issue, however, the following statement needs clarification to remove the double negative verbiage, "The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled." This statement might be improved by stating "The evidence shall be the Transmission Operators and Balancing Authorities requests have been met." This will allow the entity to show the requests received from other entities and the evidence that they filled those requests.
Response: The SDT has revised the measures based on your comments and those of others**.** **M4.** Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4. **M5**. Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled and are outside of the deadline in Requirement R1, Part 1.4.		
IRC Standards Review Committee	Yes	No comment at this time. (The YES box was inadvertently checked, which we are unable to de-select)
Northeast Power Coordinating Council	Yes	
Public Service Enterprise Group Companies	Yes	
E.ON U.S.	Yes	
Midwest ISO Standards Collaborators	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 3 Comment
PacifiCorp	Yes	
Jonathan Appelbaum	Yes	
Kasia Mihalchuk	Yes	
Jon Kapitz	Yes	
Michael Lombardi	Yes	
Leland McMillan	Yes	
Richard Kafka	Yes	
Saurabh Saksena	Yes	
Response: Thank you for your support.		

4. The implementation plan compares the already approved requirements in the "TOP" standards with those that are proposed in TOP-001-2, TOP-002-2, and TOP-003-2. When comparing the already approved standards with those that are proposed, how would you assess the impact to reliability of the proposed standards are approved and the already approved standards are retired in accordance with the implementation plan?

Summary Consideration: Some commenters said that reliability would be improved, while the vast majority of the commenters said that the changes would either not affect or would improve reliability.

Two commenters indicated reliability would suffer. Of those two, one had a technical comment that was able to be addressed directly and which should be resolved. The other had no specific comments to support the contention that reliability would be reduced as a result of these changes.

The SDT made the following changes due to comments:

TOP-001-2, R6 - Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.

Organization	Yes or No	Question 4 Comment
Joylyn Faust	There will be an adverse impact to reliability	See previous responses.
Response: Please see previous comment responses.		
Jason Shaver	There will be an adverse impact to reliability	Operational Planning Analysis: ATC is concerned with the use of the term Operational Planning Analysis in both TOP-001 and TOP-002. Once something is called an Operational Planning Analysis all associated requirements apply. Although the SDT is attempting to draw a distiction between contengency analysis which typically runs off and EMS and more traditiional PSS/E or power flow studies those requirements that talk about monitor or access to information apply equally. Example: If an entity chooses to uses a Eastern Interconnection base model to satisfy TOP-002 Requirement 1 that entity would have to also have to be in compliance with TOP-001 Requirement 13. Requirement 13 states that the TOP has to monitor or have access to information about condition and Facilities. By default a TOP would have to have access to information about every facility in the Eastern Interconnection model in order to be in compliance with calling

Organization	Yes or No	Question 4 Comment
		the study a Operational Planning Analysis and By using the same term to represent different study time frames causes a number of compliance issues with this standard. We suggest that the team either determines a single meaning for the term Operational Planning Analysis or clarifies the compliance obligations around the different time frames for Operational Planning Analysis.
Response: This requirement has been deleted from this project as it has been re-assigned to Project 2009-02 Real-time Monitoring and Analysis Capabilities.		
MRO's NERC Standards Review Subcommittee	There will be no change to reliability	There seems to be a general lack of consistency in the use and meaning of terms relating to remote measurement and remote control of the BES in the TOP, COM and PRC standards. A better glossary would ensure consistent verbiage between the standards groups. The glossary term "Telemetering" is confusingly similar to the one for "SCADA". It wrongfully includes remote control as part of the definition. We suggest it be removed from the glossary and this project.
Response: The SDT agrees with your suggestion and has changed to "telemetry." The SDT cannot change other standards that are outside the scope of this project. The commenter may submit a SAR to correct this issue in every standard that has either term present. **TOP-001-2, R6 -** Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering~~ telemetry, ~~and~~ control equipment and associated communication channels between the affected entities.		
Greg Rowland	There will be no change to reliability	These revised standards (including our proposed changes), provide more clarity and will improve compliance documentation, but we don't view that as a reliability improvement. Redline Posting for TOP-001-2 has a slight different definition than the Implementation Plan for Project 2007-03: Real-Time OperationsReliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency.Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.Duke prefers the first definition. It is the one based on the definition of "Emergency" since it doesn't mention "actual or expected".
Response: The SDT has updated the Reliability Directive definition in TOP-001-2 to match the definition in the Implementation Plan and the one originally developed by the RCSDT in Project 2006-06. **Reliability Directive** — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is		

Organization	Yes or No	Question 4 Comment
necessary to address an actual or expected Emergency.		
RoLynda Shumpert	Reliability will be improved	It appears that there are a number of instances in the Implementation Plan where the 'Resolution' points to the incorrect requirement in the proposed standard. Many times it is off by 1 requirement.
Response: A clerical error occurred in this posting that has been corrected.		
Dominion	Reliability will be improved	While the changes remove potential ambiguity from the reliability requirements, we believe that BAs, TOPs and RCs, in almost all circumstances, understand the roles they play to insure reliable grid operations. We believe these changes are predominately the result of an increased focus on compliance related activities (audit) and industry requests for clarity. We do agree that the change in R8 is an improvement as it will allow TOP and RC to focus on the limited set of SOLs that could have an adverse impact on the BES. Dominion would also like to make a general statement concerning the VSLs for all of these standards. We are unsure as to whether the correct threshold for Low, Moderate, High and Severe is correctly identified but have no basis for a denial or suggested change. We are curious as to how the various SDTs came up with these. In some draft standards, these thresholds seem to be developed around 25% quartiles, which makes it easier to accept the high and severe categories if you consider these equivalent to a pass/fail (D or F).
Response: Regarding the VSL percentages, the SDT applied these consistent with directions from FERC that indicated that the percentage bandwidths in each severity level of a VSL should be in 5% increments. No change made.		
Northeast Power Coordinating Council	There will be no change to reliability	No change to reliability assumes that the SOLs identified as a result of the Operational Planning Analysis by the Transmission Operator as supporting its local area reliability can ensure that all the existing SOLs that are being monitored and observed (for non-exceedance) by TOPs are identified through this process. Failure to identify any such SOLs will make the system vulnerable to unreliable operation.
FirstEnergy	There will be no change to reliability	We commend the hard work of the drafting team, but find it difficult to determine if these changes will affect the reliability of the BES.
Dan Rochester	There will be no change to	Our assessment that there should be no change to reliability is made on the assumption that the SOLs identified as a result of the Operational Planning Analysis by the Transmission Operator as supporting its local area reliability can ensure that all the existing SOLs that are being monitored and observed (for non-

Organization	Yes or No	Question 4 Comment
	reliability	exceedance) by TOPs are identified through this process. Failure to identify any such SOLs will expose the system to unreliable operation.
Jonathan Appelbaum	There will be no change to reliability	The team has rationalized the existing Standards and Requirements
Terry Harbour	There will be no change to reliability	Depending upon how SOLs are implemented and enforced there could be a negative impact to system reliability as transmission outages are further restricted reducing long-term maintenance to maximize short term risks to penalties.
E.ON U.S.	There will be no change to reliability	
Midwest ISO Standards Collaborators	There will be no change to reliability	
Bonneville Power Administration	There will be no change to reliability	
PJM	There will be no change to reliability	
IRC Standards Review Committee	There will be no change to	

Organization	Yes or No	Question 4 Comment
	reliability	
Western Electricity Coordinating Council	There will be no change to reliability	
L Zotter, S Solis, C Frosch, JC Culberson, S Myers, S Jue, M Morais, C Thompson	There will be no change to reliability	
John Fish	There will be no change to reliability	
Kasia Mihalchuk	There will be no change to reliability	
Jon Kapitz	There will be no change to reliability	
Saurabh Saksena	There will be no change to reliability	
Catherine Koch	There will be no change to	

Organization	Yes or No	Question 4 Comment
	reliability	
Michael Gammon	There will be no change to reliability	
Response: Thank you for your comment.		
PacifiCorp	Reliability will be improved	The proposed standards will improve reliability because the new standards provide a much more clear and streamlined approach than in the already approved standards. This will also enable responsible entities to focus their time on compliance with standards that improve reliability rather than be concerned with compliance with poorly written or redundant standards.
SERC OC Standards Review Group	Reliability will be improved	"The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Southern Company Transmission	Reliability will be improved	Southern's comments none SERC's comments: Southern participated in developing these comments and support them Although we feel that reliability will be improved, we cannot determine whether the language that was inserted specifically in response to order 693 is not arbitrary, capricious or otherwise deleterious to reliability.
Darryl Curtis	Reliability will be improved	
Public Service Enterprise Group Companies	Reliability will be improved	
Michael Lombardi	Reliability will be improved	

Organization	Yes or No	Question 4 Comment
Leland McMillan	Reliability will be improved	
Richard Kafka	Reliability will be improved	
Response: Thank you for your support.		
Randi Woodward		Minnesota Power does not have any comments at this time.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. The last draft was the fourth posting of the revised standards and represents one additional posting that was not anticipated. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	1Q11
2. Post for recirculation ballot.	2Q11
3. Submit to BOT.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated on a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

A. Introduction

1. **Title:** **Coordination of Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

   4.4. Distribution Providers

   4.5. Load-Serving Entities

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity informs its Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetry, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 within 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with issued, identified, Reliability Directive(s) in accordance with Requirement R2.

M3. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and all other Transmission Operators that it knew or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. Each Transmission Operator shall make available upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M5. Each Transmission Operator shall make available upon request, evidence that it informed other Transmission Operators of its operations known or expected to result in an Adverse Reliability

Impact on those respective Transmission Operator Areas in accordance with Requirement R5 unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M6. Each Transmission Operator, Balancing Authority, and Generator Operator shall make available upon request, evidence that it notified the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetry, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration exceeding 30 minutes as specified in Requirement R8 and in Requirement R9. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 within 30 minutes, in accordance with Requirement R11. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with a Reliability Directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by its Transmission Operator, and the respective entity did not inform the Transmission Operator of its inability to do so.
R3	The Transmission Operator did not inform one other known or expected to be affected Transmission Operator or 5% or less of the other Transmission Operators known or expected to be affected whichever is less by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other known or expected to be affected Transmission Operators or more than 5% or less than or equal to 10% of the known or expected to be affected Transmission Operators whichever is less by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other known or expected to be affected Transmission Operators or more than 10% or less than or equal to 15% of the known or expected to be affected Transmission Operators whichever is less by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other known or expected to be affected Transmission Operators or more than 15% of the known or expected to be affected Transmission Operators whichever is less by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting entity had implemented its comparable

	Lower	Moderate	High	Severe
				emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
For the Requirement R5 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R5	The Transmission Operator did not inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas with one affected reliability entity or 5% or less of the affected reliability entities whichever is less when conditions did permit such communications.	The Transmission Operator did not inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas with two affected reliability entities or more than 5% or less than or equal to 10% of the affected reliability entities whichever is less when conditions did permit such communications.	The Transmission Operator did not inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas with three affected reliability entities or more than 10% or less than or equal to 15% of the affected reliability entities whichever is less when conditions did permit such communications.	The Transmission Operator did not inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas with four or more affected reliability entities or more than 15% of the affected entities whichever is less when conditions did permit such communications.
R6	The responsible entity did not notify negatively impacted interconnected NERC registered entities of its respective planned outages of telemetry, control equipment, and associated communication channels with one negatively impacted interconnected NERC registered entities or 5% or less of the affected entities whichever is less.	The responsible entity did not notify negatively impacted interconnected NERC registered entities of its respective planned outages of telemetering and control equipment and associated communication channels with two negatively impacted interconnected NERC registered entities or more than 5% or less than or equal to 10% of the affected entities whichever is less.	The responsible entity did not notify negatively impacted interconnected NERC registered entities of its respective planned outages of telemetering and control equipment and associated communication channels with three negatively impacted interconnected NERC registered entities or more than 10% or less than or equal to 15% of the affected entities whichever is less.	The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetry, control equipment, and associated communication channels. OR, The responsible entity did not notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of its respective planned outages of telemetering and control equipment and associated communication channels with four or more negatively impacted interconnected NERC registered entities or more than 15% of the affected entities whichever is less.

	Lower	Moderate	High	Severe
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v,}$ or of an SOL identified in Requirement R8 within 30 minutes.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

Standard Development Roadmap

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1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
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4. SAR version 2 comment period closed on September 7, 2007.
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6. First posting of revised standards on October 7, 2008.
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8. Third posting of revised standards on August 25, 2009.
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Anticipated Actions	Anticipated Date
1. Post for ballot.	1Q11
2. Post for recirculation ballot.	2Q11
3. Submit to BOT.	3Q11

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated on a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive ~~-~~— A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

A. Introduction

1. **Title:** **Coordination of Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).

4. **Applicability**

    4.1. Balancing Authorities

    4.2. Transmission Operators

    4.3. Generator Operators

    4.4. Distribution Providers

    4.5. Load-Serving Entities

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity informs its Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform ~~a~~an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and all other Transmission Operators that are known or expected to be affected ~~of~~by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall ~~coordinate~~inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas ~~with those Transmission Operators~~ unless conditions do not permit such ~~coordination~~communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall ~~coordinate~~ notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering and~~telemetry, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its ~~local~~internal area reliability based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Real-time Operations]*

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v~~,~~ or of an SOL identified in Requirement R8 within 30 minutes. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

~~**R12.** Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities within its Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*~~

~~**R13.** Each Transmission Operator shall monitor, or shall have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Same-day Operations, Operations Planning]*~~

~~**R14.** Each Transmission Operator shall provide approval rights for planned maintenance of its monitoring and analysis capabilities to its System Operators. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*~~

C. Measures

M1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence that it either: (a) complied with each Reliability Directive issued by the Transmission Operator or, (b) informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission

Operator of its inability to comply with issued, identified, Reliability Directive(s) in accordance with Requirement R2.

M3. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and all other Transmission Operators that it knew or expected to be affected ~~of~~by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. Each Transmission Operator shall make available upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M5. Each Transmission Operator shall make available upon request, evidence that ~~operations~~ it ~~coordinated~~informed other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas ~~with those Transmission Operators~~ in accordance with Requirement R5 unless conditions did not permit such ~~coordination~~communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M6. Each Transmission Operator, Balancing Authority, and Generator Operator shall make available upon request, evidence that it notified the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetering and~~ telemetry, control equipment, and associated communication channels ~~were coordinated among impacted reliability entities~~ in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M8. Each Transmission Operator shall make available evidence that it has informed ~~it's~~its Reliability Coordinator of each ~~SOLs~~SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its ~~local~~internal area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration exceeding 30 minutes as specified in Requirement R8 and in Requirement R9. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an

SOL identified in Requirement R8, has been exceeded in accordance with Requirement ~~R9~~R10. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 within 30 minutes, in accordance with Requirement ~~R10~~R11. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

~~**M12.** Each Transmission Operator shall make available evidence that it can monitor, or has access to information about, conditions and Facilities within its Transmission Operator Area in accordance with Requirement R11. Such evidence could include Energy Management System description documents, computer printouts, or SCADA data collection system communications performance printouts.~~

~~**M13.** Each Transmission Operator shall make available evidence that it can monitor, or has access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area in accordance with Requirement R12. Such evidence could include Energy Management System description documents, computer printouts, or SCADA data collection system communications performance printouts.~~

~~**M14.** Each Transmission Operator shall make available evidence that its System Operators have approval rights for planned maintenance of its monitoring and analysis capabilities in accordance with Requirement R13. Such evidence could include a documented procedure that shows that the Transmission Operator's System Operator has the authority to veto planned outages to monitoring and analysis capabilities.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~Regional Entity~~

- –For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, and Generator Operator shall each keep data or evidence to show compliance for each applicable Requirement R1 through R6, R8, and R10 through ~~R14~~R11 and Measure M1 through M6, M8, and M10 through ~~M14~~M11 for the current calendar year and one previous calendar year unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Distribution Provider, Load-Serving Entity, or Generator Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with a Reliability Directive issued by the Transmission Operator, and the respective entity did not inform the Transmission Operator that such action would violate safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not comply with ~~a~~an identified Reliability Directive issued by its Transmission Operator, and the respective entity did not inform the Transmission Operator of its inability to do so.
R3	The Transmission Operator did not inform one other known or expected to be affected Transmission Operator or 5% or less of the other Transmission Operators known or expected to be affected whichever is less ~~of~~by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other known or expected to be affected Transmission Operators or more than 5% or less than or equal to 10% of the known or expected to be affected Transmission Operators whichever is less ~~of~~by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other known or expected to be affected Transmission Operators or more than 10% or less than or equal to 15% of the known or expected to be affected Transmission Operators whichever is less ~~of~~by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other known or expected to be affected Transmission Operators or more than 15% of the known or expected to be affected Transmission ~~operators~~Operators whichever is less ~~of~~by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting

	Lower	Moderate	High	Severe
				entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
For the Requirement R5 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R5	The Transmission Operator did not ~~coordinate~~inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas with one affected reliability entity or 5% or less of the affected reliability entities whichever is less when conditions did permit such ~~coordination~~communications.	The Transmission Operator did not ~~coordinate~~inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas with two affected reliability entities or more than 5% or less than or equal to 10% of the affected reliability entities whichever is less when conditions did permit such ~~coordination.~~communications.	The Transmission Operator did not ~~coordinate~~ inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas with three affected reliability entities or more than 10% or less than or equal to 15% of the affected reliability entities whichever is less when conditions did permit such ~~coordination.~~ communications.	The Transmission Operator did not ~~coordinate~~ inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on ~~other~~those respective Transmission Operator Areas with four or more affected reliability entities or more than 15% of the affected entities whichever is less when conditions did permit such ~~coordination.~~ communications.
R6	The responsible entity did not ~~coordinate~~notify negatively impacted interconnected NERC registered entities of its respective planned outages of ~~telemetering and~~telemetry, control equipment, and associated communication channels with one ~~affected reliability entity~~ negatively impacted interconnected NERC registered entities or 5% or less of the affected entities whichever is less.	The responsible entity did not ~~coordinate~~notify negatively impacted interconnected NERC registered entities of its respective planned outages of telemetering and control equipment and associated communication channels with two ~~affected reliability~~negatively impacted interconnected NERC registered entities or more than 5% or less than or equal to 10% of the affected entities whichever is less.	The responsible entity did not ~~coordinate~~ notify negatively impacted interconnected NERC registered entities of its respective planned outages of telemetering and control equipment and associated communication channels with three ~~affected reliability~~negatively impacted interconnected NERC registered entities or more than 10% or less than or equal to 15% of the affected entities whichever is less.	The responsible entity did not ~~coordinate~~notify the Reliability Coordinator of its respective planned outages of telemetry, control equipment, and associated communication channels. OR, The responsible entity did not notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of its respective planned outages of telemetering and control equipment and associated communication channels with four or more ~~affected~~

	Lower	Moderate	High	Severe
				~~reliability~~negatively impacted interconnected NERC registered entities or more than 15% of the affected entities whichever is less.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its local area reliability**.**
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement ~~R9~~R8 for a continuous duration greater than 30 minutes.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 within 30 minutes.

	Lower	Moderate	High	Severe
~~**R12**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not have monitoring capability, or access to information about, the conditions and Facilities within its Transmission Operator Area.~~
~~**R13**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not monitor, or have access to information about, conditions and Facilities identified in its Operational Planning Analysis within any Transmission Operator Area.~~
~~**R14**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator's System operator did not have approval rights for planned maintenance of its monitoring and analysis capabilities.~~

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that Transmission Operators have plans for operating within specified limits.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale for Requirement R1:

Operational Planning Analysis (OPA) does not specifically cite additional Contingency analysis (which may be performed in Real-time), but the OPA contains system constraints which are based on a methodology that captures system Contingencies (FAC-011-2).

By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have a process for performing the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, it may be completed by procedures or by tools but if tools are used, the Transmission Operator must be able to complete the analysis even if those tools are not available.

R2. Each Transmission Operator shall plan to preclude operating in excess of each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has planned to preclude operating in excess of each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator does not have an Operational Planning Analysis that represented projected System conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one registered entity or 5% or less of the reliability entities whichever is less, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two registered entities or more than 5% and less than or equal to 10% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three registered entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more registered entities or more than 15% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Changes pursuant to Project 2007-03	Revised

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7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. The last draft was the fourth posting of the revised standards and represents one additional posting that was not anticipated. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	1Q11
2. Post for recirculation ballot.	2Q11
3. Submit to BOT.	3Q11

Definitions of Terms Used in Standard

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that ~~reliability entities~~Transmission Operators have ~~coordinated~~ plans for ~~meeting expected~~ operating ~~conditions~~within specified limits.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

> Rationale for Requirement R1:
>
> Operational Planning Analysis (OPA) does not
>
> ~~Rationale for Requirement R1:~~
>
> ~~By definition, Operational Planning Analysis includes Contingency analysis.~~
>
> ~~By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have analysis tools or procedures to perform the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, if tools are used, the Transmission Operator must be able to complete the analysis even if those tools are not available.~~
>
> the analysis even if those tools are not available.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. ~~.~~ *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall plan to preclude operating in excess of ~~those~~each Interconnection Reliability Operating ~~Limits (IROLs~~Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its ~~local~~internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has planned to preclude operating in excess of ~~the IROLs~~each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its ~~local~~internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all ~~reliability~~registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~Regional Entity~~

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator does not have an Operational Planning Analysis that represented projected System conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not plan to preclude operating in excess of ~~those IROLs~~each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its ~~local~~internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one ~~reliability~~registered entity or 5% or less of the reliability entities whichever is less, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two ~~reliability~~registered entities or more than 5% and less than or equal to 10% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three ~~reliability~~registered entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more ~~reliability~~registered entities or more than 15% of the reliability entities whichever is less, identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
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Proposed Action Plan and Description of Current Draft:

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for ballot.	1Q11
2. Post for recirculation ballot.	2Q11
3. Submit to BOT.	3Q11

Definitions of Terms Used in Standard

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Owners.

   4.4. Generator Operators.

   4.5. Interchange Authorities.

   4.6. Load-Serving Entities.

   4.7. Transmission Owners.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of required data to be exchanged including, but not limited to:

- Long term outages of Bulk Electric System (BES) Facilities.
- Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES.

1.2. A mutually agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R1.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

M5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall retain evidence for 90 calendar days that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4 and Measurement M4.
-

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include two of the required elements of the documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	N/A	The responsible entity did not include a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.
R2	The Transmission Operator did not distribute its data specification to one reliability entity or 5% or less of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to two reliability entities or more than 5% and less than or equal to10% of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to four or more reliability entities or more than 15% of the entities whichever is less, that have Facilities monitored by the Transmission Operator or that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to one reliability entity or 5% or less of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to one reliability entity or 5% or less of the reliability entities whichever is less that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to two reliability entities or more than 5% and less than or equal to 10% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to two reliability entities or more than 5% and less than or equal to 10% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to three reliability entities or more than 10% and less than or equal to 15% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to four or more reliability entities or more than 15% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to four or more reliability entities or more than 15% of the reliability entities whichever is less that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R2 or R3 did not satisfy the obligations of the documented specifications for data.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
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2. **Number:** TOP-003-2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their functional responsibilities.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Owners.

   4.4. Generator Operators.

   4.5. Interchange Authorities.

   4.6. Load-Serving Entities.

   4.7. Transmission Owners.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall ~~have~~create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of required data to be exchanged including, but not limited to:

- Long term outages of Bulk Electric System ~~equipment, as specified by the Transmission Operator or Balancing Authority~~(BES) Facilities.
- Operating parameters for ~~equipment~~ BES Facilities and Facilities at voltage levels lower than the ~~Bulk Electric System, at the discretion of the Transmission Operator or Balancing Authority~~BES.

1.2. A mutually agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Transmission Operator shall distribute its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R3. Each Balancing Authority shall distribute its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~Each Transmission Operator and Balancing Authority shall provide to other Transmission Operators and Balancing Authorities, the data requested by those other Transmission Operators and Balancing Authorities necessary for Operational Planning Analysis and Real-time monitoring. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*~~

C. Measures

M1. Each Transmission Operator and Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R1.

M2. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M3. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M4. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. ~~The evidence shall be that there are no Transmission Operators as identified in Requirement R2 or Balancing Authorities as identified in Requirement R3 with outstanding requests for data to the subject entity that have been unfilled.~~ Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

M5.

~~**M6.** Each Transmission Operator and Balancing Authority shall make available evidence that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities necessary for Operational Planning Analysis and Real-time operation in accordance with Requirement R5. The evidence shall be that there are no Transmission Operators or Balancing Authorities with outstanding requests for data to the subject responsible entity that have been unfilled.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

~~Regional Entity~~

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.3. Data Retention

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator and Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator in accordance with Requirement R2 and Measurement M2.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall retain evidence for 90 calendar days that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4 and Measurement M4.
- ~~Each Transmission Operator and Balancing Authority shall retain evidence for 90 calendar days that it has provided to other Transmission Operators and Balancing Authorities the data requested by those entities~~

~~necessary for Operational Planning Analysis and Real-Time operations in accordance with Requirement R5 and Measurement M5.~~

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The responsible entity did not ~~have~~include one of the required elements of the documented specification for the data necessary for ~~them~~it to perform ~~their~~its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not ~~have~~include two of the required elements of the documented specification for the data necessary for ~~them~~it to perform ~~their~~its required Operational Planning Analyses and Real-time monitoring.	N/A	The responsible entity did not ~~have~~include a documented specification for the data necessary for ~~them~~it to perform ~~their~~its required Operational Planning Analyses and Real-time monitoring.
R2	The Transmission Operator did not distribute its data specification to one reliability entity or 5% or less of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or ~~to one reliability entity or 5% or less of the entities whichever is less,~~ that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to two reliability entities or more than 5% and less than or equal to10% of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or ~~to two reliability entities or more than 5% and less than or equal to 10% of the entities whichever is less,~~ that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that have Facilities monitored by the Transmission Operator or ~~three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less,~~ that provide Facility status to the Transmission Operator.	The Transmission Operator did not distribute its data specification to four or more reliability entities or more than 15% of the entities whichever is less, that have Facilities monitored by the Transmission Operator or ~~four or more of the reliability entities or more than 15% of the reliability entities whichever is less,~~ that provide Facility status to the Transmission Operator.
R3	The Balancing Authority did not distribute its data specification to one reliability entity or 5% or less of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to one reliability entity or 5% or less of the reliability entities whichever is less~~,~~ that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to two reliability entities or more than 5% and less than or equal to 10% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to two reliability entities or more than 5% and less than or equal to 10% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to three reliability entities or more than 10% and less than or equal to 15% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority.	The Balancing Authority did not distribute its data specification to four or more reliability entities or more than 15% of the entities whichever is less, that have Facilities monitored by the Balancing Authority and to four or more reliability entities or more than 15% of the reliability entities whichever is less~~,~~ that provide Facility status to the Balancing Authority.
R4	N/A	N/A	N/A	The responsible entity receiving a data

				specification in Requirement R2 or R3 did not satisfy the obligations of the documented specifications for data.
~~R5~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity did not provide to other Transmission Operators or Balancing Authorities the data and information requested by those entities necessary for Operational Planning Analysis and Real-time monitoring.~~

E. **Regional Variances**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

Implementation Plan for Project 2007-03: Real-Time Operations

Prerequisite Approvals

Some changes made in this project are dependent on corresponding changes being approved in Project 2006-06, Reliability Coordination:

- COM-001-1: Telecommunications
- COM-002-2: Communications and Coordination
- IRO-001-1: Reliability Coordination – Responsibilities and Authorities
- IRO-002-1: Reliability Coordination – Facilities
- IRO-014-1: Procedures to Support Coordination between Reliability Coordinators
- IRO-015-1: Notifications and Information Exchange between Reliability Coordinators
- IRO-016-1: Coordination of Real-Time Activities between Reliability Coordinators
- PER-004-1: Reliability Coordination – Staffing
- PRC-001-1: System Protection Coordination

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

Two drafting teams (Project 2006-06 and Project 2007-03) have coordinated on a common definition and agreed that the Reliability Coordination Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference.

Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

Compliance with Standard

There are three standards associated with this project for which industry approval will be requested: TOP-001-2: Coordination of Transmission Operations, TOP-002-3: Operations Planning, and TOP-003-1: Operational Reliability Data.

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							
TOP-001-2: Coordination of Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X		X
TOP-004-2: Real-Time Transmission Operations	Retired							
TOP-005-2: Operational Reliability Data	Retired							

TOP-006-1: Monitoring System Conditions	Retired
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired
TOP-008-1: Response to Transmission Limit Violations	Retired

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

Effective Date of Revised Standards
All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

The twenty-four month period is to allow for entities to update processes, develop data specifications, and train operators on the revised requirements.

Retirement Date for Existing Standards
All requirements will be retired twenty-four months following the first day of the first quarter following regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements will be retired effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

Mapping Table

The following table indicates the disposition of the existing standards requirements related to this project.

TOP-001-1	
R1 - Existing	Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.
R1 - Resolution	Deleted – Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. Needed actions required for reliability of the bulk power system have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the

	Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.
R2 - Existing	Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.
R2 - Resolution	This has been replaced by proposed TOP-001-2, Requirement R11. The undefined term 'operating emergencies' is no longer utilized and the requirement has been made more stringent by not restricting Transmission Operator actions to that undefined condition. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant timeframe.
R3 - Existing	Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.
R3 - Resolution	Deleted - This requirement is now covered in the proposed IRO-001-2, Requirements R2 & R3.
R4 - Existing	Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.
R4 - Resolution	Retained and moved to proposed TOP-001-2, Requirement R1.
R5 - Existing	Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.
R5 - Resolution	Retained and moved to proposed TOP-001-2, Requirement R3. The intent of the "mitigation" phrasing was replaced by proposed TOP-001-2, Requirement R11. (Also, see explanation for R2 above.)
R6 - Existing	Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate

	safety, equipment, or regulatory or statutory requirements.
R6 - Resolution	Retained and moved to proposed TOP-001-2, Requirement R4 for the Transmission Operator. The Generator Operator was removed since they can't be contacted directly by others and will only respond to such requests if they were in the form of a Reliability Directive from its Transmission Operator which is covered in proposed TOP-001-2, Requirement R1. The proposed EOP-001-2, Requirement R1 covers the Balancing Authority so to eliminate a redundancy the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission Operator as stated in proposed TOP-001-2, Requirement R1.
R7 - Existing	Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: 7.1 - For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. 7.2 - For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. 7.3 - When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.
R7 - Resolution	Retained but re-worded as part of proposed TOP-001-2, Requirement R5. After the fact notifications have been deleted since those actions will be seen through telemetry as cited in the proposed TOP-003-2 and proposed IRO-001-2. The term 'burden' was considered by the SDT to be vague, ambiguous, unmeasurable, and undefined and has been replaced by a NERC defined term 'Adverse Reliability Impact'.
R8 - Existing	During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load

	shedding.
R8 - Resolution	Real Power Balance and Reactive Power Balance are not defined terms. First sentence – Deleted due to: The Balancing Authority is covered in approved EOP-002-2.1, Requirement R6. Therefore, this portion of the requirement is redundant and can be deleted. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5. Approved VAR-001-1, Requirement R8 covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 (see proposed TOP-001-2, Requirement R1) and can therefore be deleted from this part of the requirement. Second sentence – Deleted due to: The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and can thus be deleted. Transmission Operators are covered under approved VAR-001-1, Requirement R1 thus making this part of the requirement redundant. Third sentence – The Reliability Coordinator is now covered in approved IRO-009-1, Requirements R1 and R2 and can be deleted here. The Transmission Operator and Balancing Authority are covered in approved EOP-003-1, Requirement R1. Therefore, this sentence is redundant and can be deleted.
TOP-002-2	
R1 - Existing	Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.
R1 - Resolution	First sentence – Deleted for Balancing Authority, Retained for Transmission Operator - The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-0 and the proposed BAL-002-1 and must take action per approved EOP-002-2.1, Requirement R6 and thus can be deleted. Retained for Transmission Operator in proposed TOP-002-3, Requirements R1 through R3. This is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator. Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities as per their certification as NERC registered entities.
R2 - Existing	Each Balancing Authority and Transmission Operator shall ensure its

	operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.
R2 - Resolution	The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted.
R3 - Existing	Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.
R3 - Resolution	For all but the Transmission Service Provider, proposed TOP-003-2 requires the transfer of any and all data required for Real-time operations or Operational Planning Analyses regardless of timeframe involved. That makes this requirement redundant and it can be deleted. The Transmission Service Provider provisions are deleted due to: • Proposed MOD-001-1a, Requirement R1: Transmission Operators select transfer capability methodology from proposed MOD-028, -029, or -030. • Proposed MOD-030, Requirement R3: Transmission Operator gives transmission model updated at least once per day to Transmission Service Provider • Proposed MOD-001-1a, Requirement R2: Transmission Service Providers use the methodology designated in proposed MOD-001-1a, Requirement R1 by the Transmission Operator.
R4 - Existing	Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.
R4 - Resolution	Proposed TOP-003-2 requires the transfer of any and all data required for Real-time operations or Operational Planning Analyses between and amongst Balancing Authorities and Transmission Operators regardless of timeframe involved. That makes this requirement redundant and it can be deleted for Balancing Authorities and Transmission Operators. Data requirements for Reliability Coordinators are covered in approved IRO-010-1, Requirement R3 making this requirement redundant for Reliability Coordinators so the Reliability Coordinator has been removed.
R5 - Existing	Each Balancing Authority and Transmission Operator shall plan to

	meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.
R5 - Resolution	The Balancing Authority is covered by approved BAL-001-0.1a and thus can be deleted. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2. Transmission Operator - replaced by proposed TOP-002-3, Requirement R1.
R6 - Existing	Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.
R6 - Resolution	The Balancing Authority is covered by approved BAL-002-0 and proposed BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6 and thus can be deleted. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2. Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. The n-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning. The SDT does not believe that there is a need for the last part of the

	sentence ‘in accordance with…’ with the advent of the ERO and enforceable reliability standards. As stated in the NERC Functional Model V5: “ the Balancing Authority’s mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation.” To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and BAL-002-0 (and the proposed BAL-002-1), Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any system condition. Balancing Authorities are not responsible for the operation of the transmission system. The Transmission Operator is responsible for the real-time operating reliability of the transmission assets under its purview, and as such has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding load, generation and interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or load shedding). If the Balancing Authorities’ actions do not resolve the transmission issues, it is the Transmission Operators’ or Reliability Coordinators’ responsibility to direct alternative actions.
R7 - Existing	Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.
R7 - Resolution	The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2 and therefore this requirement is redundant and can be deleted. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.
R8 - Existing	Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.
R8 - Resolution	The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and thus this requirement can be deleted. Voltage and reactive are the responsibility of the Transmission Operator and are covered under approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1 since any deliverability problems will appear as limit violations in the analysis.

R9 - Existing	Each Balancing Authority shall plan to meet Interchange Schedules and ramps.
R9 - Resolution	This is covered in approved INT-003-2, Requirement R1 and is thus redundant and can be deleted.
R10 - Existing	Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
R10 - Resolution	Balancing Authority - deleted as for transmission, the Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the Glossary and thus this requirement is not applicable to the Balancing Authority. The SDT position is that SOLs and IROLs are limits for which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. Transmission Operator - covered in proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs). As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the bulk power system information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator.
R11 - Existing	The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.
R11 - Resolution	Deleted: First sentence – SOLs are determined through the FAC-011-2 and FAC-014-2 processes so this sentence is no longer required. Second sentence - proposed TOP-003-2 requires the transfer of any and all data required for Real-time operations or Operational Planning Analyses. Third sentence – 'update… as necessary' is ambiguous and the SDT believes that proposed TOP-003-2 better covers this, so this is redundant and can be deleted.
R12 - Existing	The Transmission Service Provider shall include known SOLs or

	IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.
R12 - Resolution	Deleted as duplicative of proposed MOD-028-2 and MOD-029-2.
R13 - Existing	At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.
R13 - Resolution	Deleted as duplicative of proposed MOD-024-1 and MOD-025-1.
R14 - Existing	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: 14.1 - Changes in real and reactive output capabilities. (Retired August 1, 2007) 14.2 - Changes in real output capabilities. (Effective August 1, 2007) 14.3 - Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)
R14 - Resolution	Deleted – duplicative of proposed TOP-003-2.
R15 - Existing	Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).
R15 - Resolution	Deleted – duplicative of proposed TOP-003-2.
R16 - Existing	Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: 16.1 - Changes in transmission facility status. 16.2 - Changes in transmission facility rating.
R16 - Resolution	Deleted – duplicative of proposed TOP-003-2 and approved IRO-010-1, Requirement R3.
R17 - Existing	Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.
R17 - Resolution	Deleted - duplicative of approved IRO-010-1, Requirement R3.
R18 - Existing	Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.
R18 - Resolution	Deleted - this requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the

	measure which simply requires a list of line identifiers. The SDT feels that the true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19 - Existing	Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.
R19 - Resolution	Deleted - This is part of an entity's certification and is no longer required in standards. Furthermore, accuracy is a relative term that would be difficult to measure and assess compliance with. What is accurate? All calculated line flows are within 5% of actual flows? What if 14,999 lines out of 15,000 had calculated line flows within 5% and the 15,000th had a 6% error? Do we now call the model inaccurate and not rely on the results? How do you even define actual flows when meters have accuracy errors as well (i.e. no perfect meter exists)?
TOP-003-1	
R1 - Existing	Generator Operators and Transmission Operators shall provide planned outage information. 1.1 - Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. 1.2 - Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. 1.3 - Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.
R1 - Resolution	Deleted as duplicative of proposed TOP-003-2.
R2 - Existing	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.
R2 - Resolution	Proposed TOP-001-2, Requirement R5 requires the Transmission Operator to coordinate while proposed TOP-003-2 requires the Transmission Operator to identify the data it needs from the Balancing Authority to coordinate outages of voltage regulation equipment. Further, proposed TOP-003-2 requires the Balancing Authority to provide the data to the Transmission Operator that the Transmission

	Operator identified it needs.
R3 - Existing	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
R3 - Resolution	Retained as proposed TOP-001-2, Requirement R6.
R4 - Existing	Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.
R4 - Resolution	Deleted – The proposed IRO-001-2, Requirement R2 and IRO-005-4, Requirement R1give the Reliability Coordinator the authority to resolve the conflict.
TOP-004-2	
R1 - Existing	Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
R1 - Resolution	Moved to proposed TOP-001-2, Requirements R7 and R9.
R2 - Existing	Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.
R2 - Resolution	Moved to proposed TOP-001-2, Requirements R7and R9.
R3 - Existing	Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.
R3 - Resolution	Moved to proposed TOP-001-2, Requirements R7 and R9. These requirements are not limited by single or multiple Contingencies but are based solely on identified IROLs (and selected SOLs) regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator.
R4 - Existing	If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.
R4 - Resolution	Deleted due to the fact that the SDT has determined a better way to handle such a situation is to treat it like an IROL or restoration scenario and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is covered under proposed TOP-001-2, Requirements R7 and R9 and the approved EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power system.
R5 - Existing	Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.
R5 - Resolution	The Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the

	Reliability Coordinator, thus this requirement is a moot point under the Functional Model definitions and can be deleted.
R6 - Existing	Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: 6.1 - Monitoring and controlling voltage levels and real and reactive power flows. 6.2 - Switching transmission elements. 6.3 - Planned outages of transmission elements. 6.4 - Responding to IROL and SOL violations.
R6 - Resolution	The first sentence was deleted as it is has been superseded by the NERC Reliability Standards taken as a whole. Examples of such would be the proposed TOP-001-2. The second sentence was deleted as all of the sub-requirements are covered elsewhere: R6.1 is duplicative of approved VAR-001-1, Requirement R1 for reactive. Real power flows are covered in proposed TOP-001-2, Requirements R7 and R9. R6.2 is covered in proposed TOP-001-2, Requirement R5 R6.3 – moved to proposedTOP-001-2, Requirement R5; R6.4 – moved to proposed TOP-001-2, Requirement R11.
TOP-005-2	
R1 - Existing	Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area. 1.1 - Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.
R1 - Resolution	Deleted – covered by proposed TOP-003-2. The SDT does not believe it is necessary to develop a minimum list of the data required. Such minimum lists could stifle creativity and innovations as they assume that data needs don't change. For example, such a list now could not include phasor measurement data, as use of the data is still being explored and is not consistent across industry. However, phasor measurement data might obviate the need for other data in the minimum set. The effect is that resources would still be required to be utilized to gather and maintain the data that is outdated and no longer relevant. These resources would be better used supporting gathering the new data such as phasor measurement data. Furthermore, the NERC certification process provides certainty that the Transmission Operators are capable of identifying the necessary data to comply with the standards. Developing a minimum data set provides no more certainty that Transmission Operators will comply with the standards than having the capability determined in the certification

	process.
R2 - Existing	As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."
R2 - Resolution	Confidentiality is not a reliability issue but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.
R3 - Existing	Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
R3 - Resolution	Deleted as redundant with proposed TOP-003-2.
R4 - Existing	Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.
R4 - Resolution	Deleted as redundant to NAESB standard –All operating data that a Purchasing Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.
TOP-006-2	
R1 - Existing	Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. 1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. 1.2 - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
R1 - Resolution	R1 & R1.1 - Deleted – covered as part of the data specification requirements in proposed TOP-003-2. R1.2 - Deleted – covered by approved IRO-010-1, Requirement R3.
R2 – Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
R2 - Resolution	Deleted – covered as part of the data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by approved IRO-010-1,

	Requirement R3 and thus can be removed here.
R3 - Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.
R3 - Resolution	Deleted – as duplicative of PER-005-1 (training) and proposed TOP-003-2 (data).
R4 - Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.
R4 - Resolution	Deleted – covered as part of the data specification requirements in proposed TOP-003-2 and the requirements to respect SOLs in the proposed TOP-001-2. Balancing Authority's must forecast their area's Load to meet control performance standards making this requirement redundant for Balancing Authority's.
R5 - Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.
R5 - Resolution	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, for Transmission Operator avoiding IROLs; approved IRO-008-1, Requirement R2 for real-time assessments every 30 minutes for Reliability Coordinators.
R6 - Existing	Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
R6 - Resolution	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, for Transmission Operator avoiding IROLs.
R7 - Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.
R7 - Resolution	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, for Transmission Operator avoiding underfrequency; approved EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators.
TOP-007-0	
R1 - Existing	A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.
R1 - Resolution	Moved to proposed TOP-001-2, Requirement R10.
R2 - Existing	Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission

	system to within IROL as soon as possible, but not longer than 30 minutes.
R2 - Resolution	Moved to proposed TOP-001-2, Requirement R7
R3 - Existing	A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.
R3 - Resolution	Deleted - Covered in approved EOP-003-1, Requirements R1 And proposed EOP-003-2, Requirement R1, and proposed TOP-001-2, Requirement R11.
R4 - Existing	The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.
R4 - Resolution	Deleted as duplicative of approved IRO-008-1, Requirement R3 and IRO-002-2, Requirement R5.
TOP-008-1	
R1 - Existing	The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.
R1 - Resolution	Deleted – as duplicative of EOP-003-1, Requirements R1 and proposed TOP-001-2, Requirement R11.
R2 - Existing	Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.
R2 - Resolution	First sentence - Deleted as duplicative of proposed TOP-001-2, Requirements R7 and R9. Second sentence – deleted as this is now handled by the Reliability Coordinator as cited in approved IRO-009-1, Requirement R5.
R3 - Existing	The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.
R3 - Resolution	Delete first sentence – Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. The SDT reaffirms that a standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse. Delete second sentence – no longer needed as first sentence was deleted.
R4 - Exisitng	The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This

	analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.
R4 - Resolution	Deleted – information is covered as part of the data specification requirements in proposed TOP-003-2. Analysis tools are covered in the certification process for initial core capabilities. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Operational Planning Analyses are required in proposed TOP-002-3 while real-time analysis is required for IROL mitigation in proposed TOP-001-2 thus covering the operational timeframes. Proposed TOP-001-2, R11 covers mitigation of limit violations.
PER-001-0	
R1 - Existing	Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.
R1 - Resolution	Deleted - In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for Project 2007-03: Real-Time Operations

Prerequisite Approvals

Some changes made in this project are dependent on corresponding changes being approved in Project 2006-06, Reliability Coordination:

- COM-001-1~~ — ~~: Telecommunications
- COM-002-2~~ — ~~: Communications and Coordination
- IRO-001-1~~ — ~~: Reliability Coordination ~~—~~ – Responsibilities and Authorities
- IRO-002-1~~ — ~~: Reliability Coordination ~~—~~ – Facilities
- IRO-014-1~~ — ~~: Procedures to Support Coordination between Reliability Coordinators
- IRO-015-1~~ — ~~: Notifications and Information Exchange between Reliability Coordinators
- IRO-016-1~~ — ~~: Coordination of Real-Time Activities between Reliability Coordinators
- PER-004-1~~ — ~~: Reliability Coordination ~~—~~ – Staffing
- PRC-001-1~~ — ~~: System Protection Coordination

~~It is the intent of the SDT that Project 2006-06 and Project 2007-03 be filed together so that the changes to the different standards can be coordinated.~~

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

~~However, three separate~~Two drafting teams ~~wrote definitions for Reliability Directive. The three drafting teams~~(Project 2006-06 and Project 2007-03) have coordinated on a common definition and agreed that the Reliability Coordinati~~o~~o~~r~~n Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference~~ although it needs to be noted that this is still a draft and hasn't been approved by the industry~~.

Reliability Directive ~~—~~ – A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an actual or expected Emergency.

Compliance with Standard

There are three standards associated with this project for which industry approval will be requested: TOP-001-2: Coordination of Transmission Operations, TOP-002-3: Operations Planning, and TOP-003-1: Operational Reliability Data.

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							
TOP-001-2: Coordination of Transmission Operations	X	X		X		X	X	

TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X		X
TOP-004-2: Real-Time Transmission Operations	Retired							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-1: Response to Transmission Limit Violations	Retired							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

~~The assumption used by the SDT in establishing this Implementation Plan is that the project mentioned in the prerequisites: Project 2006-06, Reliability Coordination; has been approved prior to the implementation of this Project 2007-03, Real-Time Operations.~~

Effective Date of Revised Standards
All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

The twenty-four month period is to allow for entities to update processes, develop data specifications, and train operators on the revised requirements.

Retirement Date for Existing Standards
All requirements will be retired twenty-four months following the first day of the first quarter following regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements will be retired effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

Mapping Table

The following table indicates the disposition of the existing standards requirements related to this project.

~~Existing Requirement~~	~~Resolution~~
TOP-001-1	
R1 - Existing	Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.
R1 - Resolution	Deleted – Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. Needed actions required for reliability of the bulk power system have been more clearly

	laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.
R2 - Existing	Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.
R2 - Resolution	~~Deleted for Reliability Coordinator - The Reliability Coordinator has the ultimate responsibility for the reliability of the bulk power system and the Transmission Operator must respond to Reliability Coordinator directives as per proposed IRO-001-2, Requirement R2.~~ ~~Replaced for Transmission Operator – Based on the interpretation of the undefined term 'operating emergency' as equivalent to 'Emergency' as defined in the Glossary which points to 'Adverse Reliability Impact' which in turn points to IROLs, this has been replaced by proposed TOP-001-2, Requirements R7 through R10.~~ This has been replaced by proposed TOP-001-2, Requirement R11. The undefined term 'operating emergencies' is no longer utilized and the requirement has been made more stringent by not restricting Transmission Operator actions to that undefined condition. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant timeframe.
R3 - Existing	~~Moved for Reliability Coordinator - All references to the Reliability Coordinator and Reliability Coordinator responsibilities have been removed from the TOP standards as they are now covered in the revisions being undertaken in Project 2006-06. This requirement is now covered in the proposed IRO-001-2, Requirements R2 & R3.~~ ~~Replaced for Transmission Operator – Proposed TOP-001-2, Requirement R1 now covers the Balancing Authority and Generator Operator responding to Transmission Operator directives.~~ Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R3 - Resolution	Deleted - This requirement is now covered in the proposed IRO-001-2, Requirements R2 & R3.
R4 - Existing	Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.
R4 - Resolution	Retained and moved to proposed TOP-001-2, Requirement R1.
R5 - Existing	Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.
R5 - Resolution	Retained and moved to proposed TOP-001-2, Requirement R~~2~~3. The intent of the "mitigation" phrasing was replaced by proposed TOP-001-2, Requirement ~~R10~~R11. (Also, see explanation for R2 above.) ~~Also, this is covered in approved EOP-001-0, Requirement R3 and the proposed EOP-001-2, Requirement R2.~~
R6 - Existing	Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.
R6 - Resolution	Retained and moved to proposed TOP-001-2, Requirement ~~R3~~R4 for the Transmission Operator. The Generator Operator was removed since they can't be contacted directly by others and will only respond to such requests if they were in the form of a Reliability Directive from its Transmission Operator which is covered in proposed TOP-001-2, Requirement R1. The proposed EOP-001-~~0~~2, Requirement R1 covers the Balancing Authority so to eliminate a redundancy the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission Operator as stated in proposed TOP-001-2, Requirement R1.
R7 - Existing	Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: 7.1 - For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. 7.2 - For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission

	Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. 7.3 - When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.
R7 - Resolution	Retained ~~in concept~~ but re-worded as part of proposed TOP-001-2, ~~Requirements R4 &~~Requirement R5. After the fact notifications have been deleted since those actions will be seen through telemetry as cited in the proposed TOP-003-2 and proposed IRO-001-2. The term 'burden' was considered by the SDT to be vague, ambiguous, unmeasurable, and undefined and has been replaced by a NERC defined term '~~Burden'~~Adverse Reliability Impact'.
R8 - Existing	During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.
R8 - Resolution	Real Power Balance and Reactive Power Balance are not defined terms. First sentence – Deleted due to:~~-~~ The Balancing Authority is covered in approved EOP-002-2.1, Requirement R6. Therefore, this portion of the requirement is ~~superfluous~~redundant and can be deleted. The Transmission Operator does not balance real power so that part of the sentence can be deleted~~.~~ per the NERC Functional Model V5. Approved VAR-001-1, Requirement R8 covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 (see proposed TOP-001-2, Requirement R1) and can therefore be deleted from this part of the requirement. Second sentence – Deleted due to: The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and can thus be deleted. Transmission Operators are covered under approved VAR-001-1, Requirement R1 thus making this part of the requirement redundant. Third sentence – The Reliability Coordinator is now covered in approp~~pos~~ved IRO-009-1, Requirements R1 ~~through R4~~and R2 and can

	be deleted here. The Transmission Operator and Balancing Authority are covered in approved EOP-003-1, Requirement R1. Therefore, this sentence is redundant and can be deleted.
TOP-002-2	
R1 - Existing	Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.
R1 - Resolution	First sentence – Deleted for Balancing Authority, Retained for Transmission Operator - The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-0 and the proposed BAL-002-1 and must take action per approved EOP-002-2.1, Requirement R6 and thus can be deleted. Retained for Transmission Operator in proposed TOP-002-3, Requirements R1 through R3. This is patterned after the appro~~pos~~ved IRO-008-1, Requirement R1 for the Reliability Coordinator. Second sentence – Deleted~~.~~ ~~The Balancing Authority is covered in approved BAL-002-0, Requirement R3~~ as superfluous. Use of appropriate personnel and ~~thus is redundant and can be deleted here.~~ equipment is incumbent ~~The Transmission Operator is covered in the proposed TOP-001-2, Requirement R10 and is thus also redundant and can be deleted. In addition, approved EOP-001-2, Requirement R3 covers the Transmission Operator having plans in place~~ to ~~mitigate emergency conditions.~~responsible entities as per their certification as NERC registered entities.
R2 - Existing	Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.
R2 - Resolution	~~Deleted -~~ The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted.
R3 - Existing	Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.
R3 - Resolution	For all but the Transmission Service Provider, proposed TOP-003-2 requires the transfer of any and all data required for Real-time

	operations or Operational Planning Analyses regardless of timeframe involved. That makes this requirement redundant and it can be deleted. The Transmission Service Provider ~~is covered in the~~ provisions are deleted due to: • Proposed MOD-001-1a, Requirement R1: Transmission Operators select transfer capability methodology from proposed MOD-028~~-1, MOD~~, -029~~-1, and~~, or -030. • Proposed MOD-030~~-1 and is thus redundant and can be deleted.~~ , Requirement R3: Transmission Operator gives transmission model updated at least once per day to Transmission Service Provider • Proposed MOD-001-1a, Requirement R2: Transmission Service Providers use the methodology designated in proposed MOD-001-1a, Requirement R1 by the Transmission Operator.
R4 - Existing	Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.
R4 - Resolution	~~Deleted –~~ Proposed TOP-003-2 requires the transfer of any and all data required for Real-time operations or Operational Planning Analyses between and amongst Balancing Authorities and Transmission Operators regardless of timeframe involved. That makes this requirement redundant and it can be deleted for Balancing Authorities and Transmission Operators. Data requirements for Reliability Coordinators are covered in appro~~pos~~ved IRO-010-1, Requirement R3 making this requirement redundant for Reliability Coordinators ~~and it is therefore deleted~~so the Reliability Coordinator has been removed.
R5 - Existing	Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.
R5 - Resolution	The Balancing Authority is covered by approved BAL-001-0.1a and thus can be deleted. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-

	003-2. Transmission Operator - replaced by proposed TOP-002-3, Requirement~~s~~ R1~~ through R3~~.
R6 - Existing	Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.
R6 - Resolution	The Balancing Authority is covered by approved BAL-002-0 and proposed BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6 and thus can be deleted. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2. Transmission Operator - replaced by proposed TOP-002-3, Requirement~~s~~ R1~~ through R3.~~. The n-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning. The SDT does not believe that there is a need for the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. As stated in the NERC Functional Model ~~V4,~~V5: " the Balancing ~~Function: "Integrates resource plans ahead of time, maintains load-interchange-generation~~Authority's mission is to maintain the balance between loads and resources in real time within ~~a~~its Balancing Authority Area ~~and supports Interconnection~~by keeping its actual interchange equal to its scheduled interchange and meeting its frequency ~~in real time~~bias obligation." To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and BAL-002-0~~,~~ (and the proposed BAL-002-1), Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any system condition. Balancing Authorities are not responsible for the operation of the transmission system. The Transmission Operator is responsible for the real-time operating reliability of the transmission assets under its purview, and as such has

	the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding load, generation and interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or load shedding). If the Balancing Authorities' actions do not resolve the transmission issues, it is the Transmission Operators' or Reliability Coordinators' responsibility to direct alternative actions.
R7 - Existing	Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.
R7 - Resolution	The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2 and therefore this requirement is redundant and can be deleted. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement~~s~~ R1 ~~and R2~~. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.
R8 - Existing	Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.
R8 - Resolution	~~Deleted –~~ The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and thus this requirement can be deleted. Voltage and reactive are the responsibility of the Transmission Operator and are covered under approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1 ~~and R2.~~ since any deliverability problems will appear as limit violations in the analysis.
R9 - Existing	Each Balancing Authority shall plan to meet Interchange Schedules and ramps.
R9 - Resolution	This is covered in approved INT-003-2, Requirement R1 and is thus redundant and can be deleted.
R10 - Existing	Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
R10 - Resolution	Balancing Authority - deleted as for transmission, the Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the Glossary and thus this requirement is not applicable to the Balancing Authority. The SDT position is that SOLs and IROLs are ~~transmission items~~limits for which the Balancing Authority ~~has no information~~may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing

	Authority as to what to do in these situations. Transmission Operator - covered in proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs~~.~~). As stated in the NERC Functional Model V~~4~~5, "the Balancing ~~Authority~~Authority's mission is ~~responsible for integrating resource plans ahead of time, maintaining load-interchange-generation~~to maintain the balance between loads and resources in real time within ~~a~~its Balancing Authority Area ~~and supporting Interconnection~~by keeping its actual interchange equal to its scheduled interchange and meeting its frequency ~~in real time.~~bias obligation". The Balancing Authority does not possess the bulk power system information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator~~.~~, including scheduling and operating resources within the limits prescribed by the Transmission Operator.
R11 - Existing	The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.
R11 - Resolution	Deleted: ~~First sentence –~~First sentence – SOLs are determined through the FAC-011-2 and FAC-014-2 processes so this sentence is no longer required. Second sentence - proposed TOP-003-2 requires the transfer of any and all data required for Real-time operations or Operational Planning Analyses~~ regardless of the timeframe involved. Operational Planning Analyses are covered in proposed TOP-002-3, Requirement R1.~~. ~~Second sentence deleted as this is now covered in the proposed IRO-009-1, Requirement R5 for IROLs and the SDT has moved toward an operating philosophy for the Transmission Operator based on avoiding IROLs (and selected SOLs) and acting within the IROL~~ ~~T_v.~~ Third sentence – 'update… as necessary' is ambiguous and the SDT believes that proposed TOP-003-2~~, Requirement R1~~ better covers this~~ for studies and covered in proposed TOP-002-3, Requirement R3 for distribution~~, so this is redundant and can be deleted.
R12 - Existing	The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.
R12 - Resolution	Deleted as duplicative of proposed MOD-028-2~~,~~ and MOD-029-2~~, or MOD-030-2~~.
R13 - Existing	At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables,

	weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.
R13 - Resolution	Deleted as duplicative of ~~approved FAC-008~~proposed MOD-024-1 ~~& approved FAC-009~~and MOD-025-1~~, Requirement R1.3~~.
R14 - Existing	Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: 14.1 - Changes in real and reactive output capabilities. (Retired August 1, 2007) 14.2 - Changes in real output capabilities. (Effective August 1, 2007) 14.3 - Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)
R14 - Resolution	Deleted – duplicative of proposed TOP-003-2.
R15 - Existing	Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).
R15 - Resolution	Deleted – duplicative of proposed TOP-003-2.
R16 - Existing	Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: 16.1 - Changes in transmission facility status. 16.2 - Changes in transmission facility rating.
R16 - Resolution	Deleted – duplicative of proposed TOP-003-2 and approved IRO-010-1, Requirement R3.
R17 - Existing	Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.
R17 - Resolution	Deleted - duplicative of appro~~pos~~ved IRO-010-1, Requirement R3.
R18 - Existing	Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.
R18 - Resolution	Deleted ~~as the SDT feels that~~- this requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The SDT feels that the true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19 - Existing	Each Balancing Authority and Transmission Operator shall maintain

	accurate computer models utilized for analyzing and planning system operations.
R19 - Resolution	~~Deleted - Order 693, paragraph 1660 states that FERC is not interested in analytical tools but rather in capabilities. This requirement is tool-specific and as such is not suitable for Reliability Standards per Order 693.~~ Deleted - This is part of an entity's certification and is no longer required in standards. Furthermore, accuracy is a relative term that would be difficult to measure and assess compliance with. What is accurate? All calculated line flows are within 5% of actual flows? What if 14,999 lines out of 15,000 had calculated line flows within 5% and the 15,000th had a 6% error? Do we now call the model inaccurate and not rely on the results? How do you even define actual flows when meters have accuracy errors as well (i.e. no perfect meter exists)?
TOP-003-1	
R1 - Existing	Generator Operators and Transmission Operators shall provide planned outage information. 1.1 - Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. 1.2 - Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. 1.3 - Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.
R1 - Resolution	Deleted as duplicative of proposed TOP-003-2~~, Requirement R1~~.
R2 - Existing	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.
R2 - Resolution	~~Balancing Authority deleted since Balancing Authority is only required to respond to Reliability Directives regarding voltage.~~ ~~Proposed TOP-001-2, Requirement R4 covers coordination issues.~~ ~~Proposed TOP-003-2, Requirement R1 handles data requirements.~~ Proposed TOP-001-2, Requirement R5 requires the Transmission Operator to coordinate while proposed TOP-003-2 requires the Transmission Operator to identify the data it needs from the Balancing Authority to coordinate outages of voltage regulation equipment. Further, proposed TOP-003-2 requires the Balancing Authority to provide the data to the Transmission Operator that the Transmission Operator identified it needs.
R3 - Existing	Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering

	and control equipment and associated communication channels between the affected areas.
R3 - Resolution	Retained as proposed TOP-001-2, Requirement R6.
R4 - Existing	Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.
R4 - Resolution	Deleted – ~~covered by~~The proposed ~~TOP-001-2, Requirements R4 & R5 as the SDT expects the entities to resolve any conflicts based on this requirement. If the conflict can't be resolved, the (proposed)~~ IRO-001-2, Requirement ~~R1 gives~~R2 and IRO-005-4, Requirement R1give the Reliability Coordinator the authority to resolve the conflict.
TOP-004-2	
R1 - Existing	~~Moved to proposed TOP-001-2, R7 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.~~ Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
~~R2~~R1 - Resolution	Moved to proposed TOP-001-2, Requirements R7 ~~with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (~~and ~~selected SOLs) and the IROL T_v~~R9.
R2 - Existing	Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.
R2 - Resolution	Moved to proposed TOP-001-2, Requirements R7and R9.
R3 - Existing	Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.
R3 - Resolution	Moved to proposed TOP-001-2, Requirements R7~~. This requirement is~~ and R9. These requirements are not limited by single or multiple Contingencies but ~~is~~are based solely on identified IROLs (and selected SOLs) regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator.
R4 - Existing	If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.
R4 - Resolution	Deleted due to the fact that the SDT ~~believes the best~~has determined a better way to handle such a situation is to treat it like an IROL or restoration scenario and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is covered under proposed TOP-001-2, Requirements R7 and R9 and the appro~~pos~~ved EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power system.
R5 - Existing	Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.
R5 -	The Transmission Operator does not have the right to unilaterally

Resolution	separate – that can only be done through the authorization of the Reliability Coordinator, thus ~~the first sentence~~ this requirement is a moot point under the Functional Model definitions and ~~that portion of the requirement~~ can be deleted. ~~The second sentence has been replaced by proposed TOP-001-2, R7 through R10 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.~~
R6 - Existing	Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: 6.1 - Monitoring and controlling voltage levels and real and reactive power flows. 6.2 - Switching transmission elements. 6.3 - Planned outages of transmission elements. 6.4 - Responding to IROL and SOL violations.
R6 - Resolution	The first sentence was deleted as it is has been superseded by the NERC Reliability Standards taken as a whole. Examples of such would be the proposed TOP-001-2. The second sentence ~~can be~~was deleted as all of the sub-requirements are covered elsewhere: R6.1 is duplicative of approved VAR-001-1, Requirement R1 for reactive. Real power flows are covered in proposed TOP-001-2, Requirements R7 and R9. R6.2 is covered in proposed TOP-001-2, Requirement ~~R4~~R5 R6.3 – moved to proposedTOP-001-2, Requirement ~~R4~~R5; R6.4 – moved to proposed TOP-001-2, ~~Requirements R7 through R10 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.~~ ~~Also, a Transmission Operator must have a documented Operating Procedure covering every applicable standard requirement in order to pass an audit~~Requirement R11.
TOP-005-2	
R1 - Existing	Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area. 1.1 - Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.
R1 - Resolution	Deleted – covered by proposed TOP-003-2. The SDT does not believe it is necessary to develop a minimum list of the data required. Such minimum lists could stifle creativity and innovations as they assume that data needs don't change. For example, such a list now could not include phasor measurement data, as use of the data is still being explored and is not consistent across industry. However, phasor measurement data might obviate the need for other data in the

	minimum set. The effect is that resources would still be required to be utilized to gather and maintain the data that is outdated and no longer relevant. These resources would be better used supporting gathering the new data such as phasor measurement data. Furthermore, the NERC certification process provides certainty that the Transmission Operators are capable of identifying the necessary data to comply with the standards. Developing a minimum data set provides no more certainty that Transmission Operators will comply with the standards than having the capability determined in the certification process.
R2 - Existing	As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."
~~R1~~R2 - Resolution	Confidentiality is not a reliability issue but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.
R3 - Existing	Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
~~R2~~R3 - Resolution	Deleted ~~– covered by~~as redundant with proposed TOP-003-2.
R4 - Existing	Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.
~~R3~~R4 - Resolution	Deleted as redundant to NAESB standard –All operating data that a Purchasing Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system. ~~This is a NAESB standard and can thus be deleted.~~ ~~Purchasing Selling Entity is covered under the INT standards and thus can be deleted.~~
TOP-006-2	
R1 - Existing	Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. 1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. 1.2 - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R1 - Resolution	R1 & R1.1 - Deleted – covered as part of the ~~new~~ data specification requirements in proposed TOP-003-2. R1.2 - Deleted – covered by appro~~pos~~ved IRO-010-1, Requirement R3.
R2 – Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
R2 - Resolution	Deleted – covered as part of the ~~new~~ data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by appro~~pos~~ved IRO-010-1, Requirement R3 and thus can be removed here.
R3 - Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.
R3 - Resolution	Deleted – as duplicative of ~~proposed~~ PER-005-1 (training) and proposed TOP-003-2 (data).
R4 - Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.
R4 - Resolution	Deleted – covered as part of the ~~new~~ data specification requirements in proposed TOP-003-2 and the requirements to respect SOLs in the proposed TOP-001-2. Balancing Authority's must forecast their area's Load to meet control performance standards making this requirement redundant for Balancing Authority's.
R5 - Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.
R5 - Resolution	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, for Transmission Operator avoiding IROLs; appro~~pos~~ved IRO-008-1, Requirement R2 for real-time assessments every 30 minutes for Reliability Coordinators.
R6 - Existing	Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
R6 - Resolution	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-~~o~~0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, for Transmission Operator avoiding IROLs.
R7 - Existing	Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.
R7 - Resolution	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain

	their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, for Transmission Operator avoiding underfrequency; appro~~pos~~ved EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators.
TOP-007-0	
R1 - Existing	~~Moved to proposed TOP-001-2, R9 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.~~A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.
R1 - Resolution	Moved to proposed TOP-001-2, Requirement R10.
R2 - Existing	~~Moved to proposed TOP-001-2, R7 with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v.~~Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.
R2 - Resolution	Moved to proposed TOP-001-2, Requirement R7
R3 - Existing	A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.
R3 - Resolution	Deleted - Covered in approved EOP-003-1, Requirements R1 ~~& R3.~~ And proposed EOP-003-2, Requirement R1, and proposed TOP-001-2, Requirement ~~R10~~R11.
R4 - Existing	The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.
R4 - Resolution	Deleted as duplicative of approved IRO-~~001~~008-1~~.1.~~, Requirement R3~~.~~ and IRO-002-2, Requirement R5.
TOP-008-1	
R1 - Existing	The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.
R1 - Resolution	Deleted – as duplicative of ~~approved~~ EOP-003-1, Requirements R1~~, R3 & R5~~ and proposed TOP-001-2, Requirement ~~R10~~R11.
R2 - Existing	Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.
R2 - Resolution	First sentence - Deleted as duplicative of proposed TOP-001-2, Requirements R7 ~~with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (~~and ~~selected SOLs) and the IROL T_v.~~R9. Second sentence – deleted as this is now handled by the Reliability Coordinator as cited in appro~~pos~~ved IRO-009-1, Requirement R5.

R3 - Existing	The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.
R3 - Resolution	Delete first sentence – Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. ~~If the situation involves an IROL it is covered in proposed TOP-001-2, Requirements R7 through R10. If it is not an IROL, then the owner still has the right to protect their equipment within the limitations of their contracts and obligation to comply with the Reliability Standards.~~ ~~Delete second sentence as duplicative of proposed TOP-001-2, Requirements R4 & R5.~~ ~~The SDT feels~~ The SDT reaffirms that a standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse. Delete second sentence – no longer needed as first sentence was deleted.
R4 - Exisitng	The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.
R4 - Resolution	Deleted – information is covered as part of the ~~new~~ data specification requirements in proposed TOP-003-2. Analysis tools are covered in the certification process for initial core capabilities. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Operational Planning Analyses are required in proposed TOP-002-3 while real-time analysis is required for IROL mitigation in proposed TOP-001-2 thus covering the operational timeframes. Proposed TOP-001-2, ~~R10~~R11 covers mitigation of limit violations ~~with the note that the SDT has moved toward an operating philosophy based on avoiding IROLs (and selected SOLs) and the IROL T_v~~.
PER-001-0	
R1 - Existing	Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.
R1 - Resolution	Deleted - In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT ~~believes that~~reasonably applied this same logic ~~applies~~ to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Resolution of Issues Assigned to Real-time Operations SDT (Project 2007-03)

Standard	Source	Language	Resolution
TOP-001			
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of “emergency” and define the criteria for entering into the various states. Also define the authority for declaring these states.	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started. The TOP standards have been re-written to specifically address what a Transmission Operator is responsible for. The proposed TOP requirements are no longer restricted to the undefined term ‘operating emergency’ and are now more inclusive and stringent than the previous requirement. Indeed, the undefined term ‘operating emergency’ is no longer utilized in the proposed revisions. Therefore, any delay in defining operating states in the EOP Project has no effect on the TOP standards.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara’s comments to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	This is covered in proposed TOP-001-2, Requirement R5.
TOP-001-1	Version 0 Team	What is ‘clear decision making authority’?	Requirement using this term was deleted as not needed in a reliability standard. The standards already require the necessary actions.
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up	Requirements have been re-written to eliminate confusion.

Standard	Source	Language	Resolution
		notification as opposed to immediate	
TOP-001-1	Version 0 Team	Define emergency	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-002			
TOP-002-2	FERC Order 693	1600 - Address critical energy infrastructure confidentiality as part of the routine standard development process.	Restrictions due to confidentiality have been eliminated by re-writing the data specification requirements in proposed TOP-003-2.
TOP-00-2	FERC Order 693	1601 – Require next day analysis for all IROLs to identify and communicate control actions to system operators	See proposed TOP-002-3, Requirements R1, R2, and R3.
TOP-002-2	FERC Order 693	1603 - Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-002-2	FERC Order 693	1604/1608 - Requires simulation contingencies to match what will actually happen in the field.	This is covered in proposed TOP-002-3, Requirement R1 by the phrase "… represent projected System conditions".
TOP-002-2	FERC Order 693	1606 - Commenters did not take issue with the	Deliverability and limits are included in Operational Planning Analysis in

Standard	Source	Language	Resolution
		proposed interpretation of the term "deliverability" as "the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches."[1] The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	TOP-002-3, Requirement R1. Operational Planning Analysis contains deliverability and much more and is thus more stringent than the Order. Limit violations in the Operational Planning Analysis will show any deliverability problems regardless of type and proposed requirements mandate that these issues be resolved. In addition, the proposed requirements clearly state that an individual entity, the Transmission Operator, is wholly responsible for these concerns which is an improvement over the previous vaguely worded requirement that placed this responsibility with the Balancing Authority which has no control over the issues involved.
TOP-002-1	Fill in the Blank Team	Remove "in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements" from R6 and "in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes" from R12 .	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. Requirement R12 has been deleted as duplicative of MOD-030-2 (not yet approved).
TOP-002-2: R19	NERC Audit Observation Team	How do you address the term - verify "Accurate"	Requirement R19 was eliminated as unmeasurable.
TOP-002-2	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1.
TOP-002-1	Version 0 Team	Define N-1	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS.

[1] Id. at P 974.

Standard	Source	Language	Resolution
			For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. This term is no longer in use for this standard.
TOP-002-1	Version 0 Team	Define 'without intentional delay'	This term was considered unmeasurable and has been deleted from this standard.
TOP-002-1	Version 0 Team	Reliability should 'trump' confidentiality	The SDT has removed all references to confidentiality by re-writing the data specification requirements.
TOP-002-1	Version 0 Team	Coordination of planning required	The SDT has re-written and tightened up the requirements for distributing data and information.
TOP-002-1	Version 0 Team	Limit of 2 tests per year	This requirement has been deleted by the SDT as verification testing is not needed in this standard.
TOP-002-1	VRF Team	R9 – related to INT-003	Requirement R9 has been deleted as it is duplicative of approved INT-003-2
TOP-002-1	VRF Team	R14 & 14.1 – ambiguous	Deleted – duplicative of proposed TOP-003-2.
TOP-002-1	VRF Team	R2 – administrative in nature, not a real requirement	The SDT agreed and deleted this requirement.
TOP-003			
TOP-003-0	FERC Order 693	1620 & 1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	The SDT posed a question on this issue as a fact finding exercise in the second posting of this project in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the

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Standard	Source	Language	Resolution
			same time accommodate competitive electricity markets. After reviewing the industry comments, the SDT concluded that proposed TOP-001-2, Requirements R5 & R6 adequately cover this issue. The SDT bases this position on the requirement which includes the Operations Planning Time Horizon that covers the period from one day to one year. The requirement mandates that actions are coordinated. The SDT interprets this to include planned outages when they are known. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	FERC Order 693	1622 - Consider TVA's suggestion for including breaker outages within the meaning of facilities that are subject to advance notice for planned outages.	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	FERC Order 693	1624 - Require any facility, that in the opinion of the reliability coordinator, balancing authority, or transmission operator, will have a direct impact on the reliability of the bulk power system be subject to the requirement R1 for planned outage coordination.	New data specifications in proposed TOP-003-2, Requirement R1 (and bullets) handle this concern.
TOP-003-0	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1
TOP-003-0	Version 0 Team	Outage information needed sooner than 1 day prior	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	Version 0 Team	RA can't request outage cancellation	Deleted – now covered in Project 2006-06.
TOP-003-0	Version 0 Team	Submit outage data ASAP but no later than noon day ahead	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	VRF Team	R4 – poorly written	Deleted – now covered in Project 2006-06.
TOP-003-1	FMPA – Frank	With respect to requirement R1.2, why is the TOP	Requirement deleted as duplicative of proposed TOP-003-2, R1.

Standard	Source	Language	Resolution
	Gaffney	responsible for providing generator outage information? Isn't that the BA's or GOP's responsibility and isn't this redundant with IRO-010-1?	
		TOP-004	
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	Replaced by proposed TOP-001-2, R7 through R11. T_v is more stringent than the existing 30 minute requirement for IROLs and 30 minutes is retained for selected SOLs. Unknown states, in this context, cannot exist because valid operating limits have been determined for all Facilities in a TOP's footprint. The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to Emergencies.
TOP-004-1	FERC Order 693	1637 - Reliability coordinators should report any IROL violations to NERC on a monthly basis for one year beginning August 2, 2007.	Not within the scope of the SDT.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (. . .the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should	The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the bulk power system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

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Standard	Source	Language	Resolution
		develop a procedure to identify applicable high risk conditions. Under . . . high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	FERC Order 693	1639 - Consider Santa Clara's comments regarding changes to requirement R2 in the standards development process. (Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.)	This is covered as part of the new data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by proposed IRO-010-1, Requirement R3.
TOP-004-1	FERC Order 693	1641 - NERC should report the results of the survey to the Commission within 18 months of the effective date of this rule.	Not within the scope of the SDT.
TOP-004-1	Fill in the Blank Team	No action required	No action required.
TOP-004-1	Version 0 Team	Operations should conform to planning standards	Operations and planning are different timeframes with different problems and solutions
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	Requirement moved to proposed TOP-001-2, Requirement R5 and clarified.
TOP-004-1	Version 0 Team	Define SOL & IROL	These are defined terms in the NERC Glossary.
TOP-004-1	Version 0 Team	Clarify roles	Applicability has been reviewed and updated as necessary.
TOP-004-1	Version 0 Team	Define (or remove) practical	The term has been removed.
TOP-004-1	Version 0 Team	Specify disconnection as acceptable in R5	The requirement has been deleted. Relationships between the Reliability Coordinator and Transmission Operator as described in the revised standards cover these actions.

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Standard	Source	Language	Resolution
TOP-005			
TOP-005-1	FERC Order 693	1648 - Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.
TOP-005-1	FERC Order 693	1649 - Delete references to confidentiality agreements but ensure critical energy infrastructure confidentiality is addressed in the standards development process.	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	FERC Order 693	1650 - Consider FirstEnergy's modifications to Attachment 1 and ISO-NE's recommended revision to requirement R4 in the standards development process. ISO-NE recommends that the reference to "purchasing-selling entity" in Requirement R4 should be replaced with "generator owner, transmission owner, and LSE.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2. Requirement R4 has been superseded by proposed TOP-003-2 which does include the indicated entities.
TOP-005-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R2 of PRC-001-1 in TOP-005. Note: These requirements are being removed from PRC.	See proposed TOP-003-2, Requirement R1
TOP-005-1	Version 0 Team	Need to include GO & LSE	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Data update is too slow	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Generator data should include voltage control & stabilizers	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	GO needs to supply data to BA & TO	New data specifications in proposed TOP-003-2 handle this concern
TOP-005-1	Received for the November 4, 2009 Technical Conference on Interpretations of	NERC staff believes that the interpretation does not support the stated purpose of IRO-005-1: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability	While this issue was entered against the Transmission Operator as the interpretation request was primarily for TOP-005-1, the emphasis on such informative actions has shifted in current revision projects. The proposed IRO-010-1, Requirement R1 gives the Reliability Coordinator the right to ask for any reliability related data that they need to perform their

Standard	Source	Language	Resolution
	Standards from Manitoba Hydro	assessments. The Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.” Given that Requirement R12 pre-supposes that the SPS is armed to address inter-Balancing Authority or inter-Transmission Operator impacts (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), the argument not discussed in the interpretation is that the SPS itself with one communication channel in service can be viewed for advance planning or reliability assessment purposes as a single contingency (loss of the communication channel). The question asked by the requestor indicates that the operation of the SPS on a single channel is known ahead of the timeframe for which the SPS may be armed and that the condition was not first identified when the SPS was called to operate. In this regard, the Reliability Coordinator must be aware of the less dependable state of the SPS in order to properly assess the impact and plan for the next single contingency that it conceivably could experience. In this case, the Reliability Coordinator may wish to consider the loss of an armed SPS when performing its reliability assessments. While the Reliability Coordinator may not elect to proactively position the system to withstand the loss of the SPS that is operating on a single communication channel, the Reliability Coordinator may elect to develop a contingency plan in the event the SPS does fail to operate as designed or if the remaining communication channel is lost. The importance of the SPS relative to current or anticipated system conditions would be considerations for the	Reliability Coordinator task. And it also mandates the Transmission Operator to provide said data in Requirement R3. (Note – This standard has been approved by the BOT but has not yet been approved by FERC.)

Standard	Source	Language	Resolution
		Reliability Coordinator. This consideration only becomes possible if the Transmission Operator notifies the Reliability Coordinator that the SPS is operating on a single communication channel. Therefore, Transmission Operator notification to the Reliability Coordinator of this condition raises the Reliability Coordinator's situational awareness that may influence current or future operating conditions or decisions in a preventive rather than reactive manner. NERC staff does agree that the SPS is still mission capable with only one communication channel in service, but degraded in terms of its dependability due to the unavailability of redundant communications channels. The fact that a second communications channel was part of the original design of the SPS suggests that both channels were important to the dependability of the system, and that the unavailability of either channel causes some degradation in the overall dependability of the SPS. Additionally, the team equated "any degradation" with "potential failure to operate as expected" in IRO-005. The use of the term "or" connecting these two phrases in the standard indicates these were not intended to be equivalent. Therefore, NERC staff believes the conclusion reached by the team that the two terms are synonymous is incorrect. Further, the specific circumstances contemplated in the interpretation request are not likely to occur often and the additional burden to Transmission Operators to notify the Reliability Coordinator is de minimis when compared to the improved situational awareness that would result. On this basis, NERC staff believes the interpretation is not serving the best interests of reliability and should be remanded	

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Standard	Source	Language	Resolution
		to the team for further consideration of the NERC staff opinion.	
		TOP-006	
TOP-006-1	FERC Order 693	1660 & 1661 - Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system.	Minimum capabilities for Transmission Operators are being handled in project 2009-02, Real-time Monitoring and Analysis Capabilities. Requirement for phase angle information is covered by proposed TOP-003-2.
TOP-006-1	FERC Order 693	1663 - Clarify the meaning of “appropriate technical information” concerning protective relays. To provide more clarity, criteria that define what “appropriate technical information” is necessary should be specified so that operators can make better informed decisions.	This term is no longer used. Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and TOP-003-2 (data).
TOP-006-1	FERC Order 693	1664 - Consider APPA’s comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
TOP-006-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R6 of PRC-001-1 in TOP-003 R5 or TOP-006. Note: These requirements are being retired in PRC-001-1.	See proposed TOP-003-2, Requirement R1
TOP-006-1	Version 0 Team	Need to match roles with FM	Applicability has been reviewed by the SDT and changed as required in accordance with the FM and the Compliance Registry.
TOP-006-1	Version 0 Team	Monitor frequency at multiple points	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	Load forecasting data required	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	GO needs to provide normal & emergency data	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R1, 1.1, 1.2 – ‘available in emergency situation’ may be needed	New data specifications in proposed TOP-003-2 handle this concern.

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Standard	Source	Language	Resolution
TOP-006-1	VRFs Team	R3 – define appropriate	This requirement was deleted as duplicative of approved PRC-001-1, Requirement R1.
TOP-006-1	VRFs Team	R4 – What information is required and what is a load pattern?	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirements R1 and R1.2, why are BAs responsible for information regarding transmission resources available for use? Isn't that the role of the TOP?	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R2, why is the BA responsible for monitoring transmission line status, voltage, load tap changer settings, and reactive power in general? Monitoring and managing reactive resources, voltage and tap settings is clearly made the responsibility of the TOP in VAR-001-1a.	Deleted – SDT agrees.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R3 why does the BA need to understand protective relaying? Isn't that the role of the TOP and GOP?	Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and proposed TOP-003-2 (data).
TOP-007			
TOP-007-0	FERC Order 693	1673 - Consider the NRC's comments on voltage requirements as part of the standards development process.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-007-0	Version 0 Team	Need to define evidence of evaluation	This term isn't used in the requirements – no action required.
TOP-007-0	Version 0 Team	Need to tighten the non-compliance terms	Measures and VSL have been assigned to all requirements.

Standard	Source	Language	Resolution
TOP-007-0	Version 0 Team	Not enforceable with current criteria	Not enough information provided to address concern.
TOP-007-0	Version 0 Team	RA should be included	Reliability Coordinator is now covered in Project 2006-06.
TOP-007-0	Version 0 Team	More of a compliance issue than a true standard	Not enough information provided to address concern.
TOP-008			
TOP-008-1	FERC Order 693	1681 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
PER-001			
PER-001-0	Version 0 Team	Data retention should be 1 year	This standard will be retired.

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Resolution of Issues Assigned to Real-time Operations SDT (Project 2007-03)

Standard	Source	Language	Resolution
TOP-001			
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started. The TOP standards have been re-written to specifically address what a Transmission Operator is responsible for. The proposed TOP requirements are no longer restricted to the undefined term 'operating emergency' and are now more inclusive and stringent than the previous requirement. Indeed, the undefined term 'operating emergency' is no longer utilized in the proposed revisions. Therefore, any delay in defining operating states in the EOP Project has no effect on the TOP standards.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	This is covered in proposed TOP-001-2, Requirement R5.
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	Requirement using this term was deleted as not needed in a reliability standard. The standards already require the necessary actions.
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up	Requirements have been re-written to eliminate confusion.

Standard	Source	Language	Resolution
		notification as opposed to immediate	
TOP-001-1	Version 0 Team	Define emergency	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-002			
TOP-002-2	FERC Order 693	1600 - Address critical energy infrastructure confidentiality as part of the routine standard development process.	Restrictions due to confidentiality have been eliminated by re-writing the data specification requirements in proposed TOP-003-2.
TOP-00-2	FERC Order 693	1601 – Require next day analysis for all IROLs to identify and communicate control actions to system operators	See proposed TOP-002-3, Requirements R1, R2, and R3.
TOP-002-2	FERC Order 693	1603 - Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-002-2	FERC Order 693	1604/1608 - Requires simulation contingencies to match what will actually happen in the field.	~~To the extent possible,~~ This is covered in proposed TOP-002-3, Requirement R1 by the phrase ~~"and shall~~"… represent projected System conditions".

Standard	Source	Language	Resolution
TOP-002-2	FERC Order 693	1606 - Commenters did not take issue with the proposed interpretation of the term "deliverability" as "the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches."[1] The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	Deliverability and limits are ~~implicitly~~ included in Operational Planning Analysis in TOP-002-3, Requirement R1. Operational Planning Analysis contains deliverability and much more and is thus more stringent than the Order. Limit violations in the Operational Planning Analysis will show any deliverability problems regardless of type and proposed requirements mandate that these issues be resolved. In addition, the proposed requirements clearly state that an individual entity, the Transmission Operator, is wholly responsible for these concerns which is an improvement over the previous vaguely worded requirement that placed this responsibility with the Balancing Authority which has no control over the issues involved.
TOP-002-1	Fill in the Blank Team	Remove "in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements" from R6 and "in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes" from R12 .	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. Requirement R12 has been deleted as duplicative of MOD-030-2 (not yet approved).
TOP-002-2: R19	NERC Audit Observation Team	How do you address the term - verify "Accurate"	Requirement R19 was eliminated as unmeasurable.
TOP-002-2	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1.
TOP-002-1	Version 0 Team	Define N-1	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS.

[1] Id. at P 974.

Standard	Source	Language	Resolution
			For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. This term is no longer in use for this standard.
TOP-002-1	Version 0 Team	Define 'without intentional delay'	This term was considered unmeasurable and has been deleted from this standard.
TOP-002-1	Version 0 Team	Reliability should 'trump' confidentiality	The SDT has removed all references to confidentiality by re-writing the data specification requirements.
TOP-002-1	Version 0 Team	Coordination of planning required	The SDT has re-written and tightened up the requirements for distributing data and information.
TOP-002-1	Version 0 Team	Limit of 2 tests per year	This requirement has been deleted by the SDT as verification testing is not needed in this standard.
TOP-002-1	VRF Team	R9 – related to INT-003	Requirement R9 has been deleted as it is duplicative of approved INT-003-2
TOP-002-1	VRF Team	R14 & 14.1 – ambiguous	Deleted – duplicative of proposed TOP-003-2.
TOP-002-1	VRF Team	R2 – administrative in nature, not a real requirement	The SDT agreed and deleted this requirement.
TOP-003			
TOP-003-0	FERC Order 693	1620 & 1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	The SDT posed a question on this issue as a fact finding exercise in the second posting of this project in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC

Standard	Source	Language	Resolution
			Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. After reviewing the industry comments, the SDT concluded that proposed TOP-001-2, Requirements R5 & R6 adequately cover this issue. The SDT bases this position on the requirement which includes the Operations Planning Time Horizon that covers the period from one day to one year. The requirement mandates that actions are coordinated. The SDT interprets this to include planned outages when they are known. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	FERC Order 693	1622 - Consider TVA's suggestion for including breaker outages within the meaning of facilities that are subject to advance notice for planned outages.	New data specifications in proposed TOP-003-2 handle this concern. ~~Note – For this and other issues noted as handled by the new data specification standard: FERC staff has indicated that they do not agree with this approach as an equal and effective substitute for the approved requirements.~~
TOP-003-0	FERC Order 693	1624 - Require any facility, that in the opinion of the reliability coordinator, balancing authority, or transmission operator, will have a direct impact on the reliability of the bulk power system be subject to the requirement R1 for planned outage coordination.	New data specifications in proposed TOP-003-2, Requirement R1 (and bullets) handle this concern.
TOP-003-0	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1
TOP-003-0	Version 0 Team	Outage information needed sooner than 1 day prior	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	Version 0 Team	RA can't request outage cancellation	Deleted – now covered in Project 2006-06.
TOP-003-0	Version 0 Team	Submit outage data ASAP but no later than noon day ahead	New data specifications in proposed TOP-003-2 handle this concern.

Standard	Source	Language	Resolution
TOP-003-0	VRF Team	R4 – poorly written	Deleted – now covered in Project 2006-06.
TOP-003-1	FMPA – Frank Gaffney	With respect to requirement R1.2, why is the TOP responsible for providing generator outage information? Isn't that the BA's or GOP's responsibility and isn't this redundant with IRO-010-1?	Requirement deleted as duplicative of proposed TOP-003-2, R1.
TOP-004			
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	Replaced by proposed TOP-001-2, ~~R8~~R7 through R11~~ with the note that the SDT has moved toward an operating philosophy based on identifying, avoiding, mitigating, and responding to IROLs and the IROL T_v.~~. T_v is more stringent than the existing 30 minute requirement~~.~~ for IROLs and 30 minutes is retained for selected SOLs. Unknown states, in this context, cannot exist because valid operating limits have been determined for all Facilities in a TOP's footprint. The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to Emergencies.
TOP-004-1	FERC Order 693	1637 - Reliability coordinators should report any IROL violations to NERC on a monthly basis for one year beginning August 2, 2007.	Not within the scope of the SDT.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (. . .the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of	The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the bulk power system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under . . . high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	FERC Order 693	1639 - Consider Santa Clara's comments regarding changes to requirement R2 in the standards development process. (Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.)	This is covered as part of the new data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by proposed IRO-010-1, Requirement R3.
TOP-004-1	FERC Order 693	1641 - NERC should report the results of the survey to the Commission within 18 months of the effective date of this rule.	Not within the scope of the SDT.
TOP-004-1	Fill in the Blank Team	No action required	No action required.
TOP-004-1	Version 0 Team	Operations should conform to planning standards	Operations and planning are different timeframes with different problems and solutions
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	Requirement moved to proposed TOP-001-2, Requirement R5 and clarified.
TOP-004-1	Version 0 Team	Define SOL & IROL	These are defined terms in the NERC Glossary.
TOP-004-1	Version 0 Team	Clarify roles	Applicability has been reviewed and updated as necessary.
TOP-004-1	Version 0 Team	Define (or remove) practical	The term has been removed.
TOP-004-1	Version 0 Team	Specify disconnection as acceptable in R5	The requirement has been deleted. Relationships between the Reliability Coordinator and Transmission Operator as described in the revised

Standard	Source	Language	Resolution
			standards cover these actions.
		TOP-005	
TOP-005-1	FERC Order 693	1648 - Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.
TOP-005-1	FERC Order 693	1649 - Delete references to confidentiality agreements but ensure critical energy infrastructure confidentiality is addressed in the standards development process.	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	FERC Order 693	1650 - Consider FirstEnergy's modifications to Attachment 1 and ISO-NE's recommended revision to requirement R4 in the standards development process. ISO-NE recommends that the reference to "purchasing-selling entity" in Requirement R4 should be replaced with "generator owner, transmission owner, and LSE.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2. Requirement R4 has been superseded by proposed TOP-003-2 which does include the indicated entities.
TOP-005-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R2 of PRC-001-1 in TOP-005. Note: These requirements are being removed from PRC.	See proposed TOP-003-2, Requirement R1
TOP-005-1	Version 0 Team	Need to include GO & LSE	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Data update is too slow	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Generator data should include voltage control & stabilizers	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	GO needs to supply data to BA & TO	New data specifications in proposed TOP-003-2 handle this concern
TOP-005-1	Received for the November 4, 2009 Technical Conference on	NERC staff believes that the interpretation does not support the stated purpose of IRO-005-1: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area	While this issue was entered against the Transmission Operator as the interpretation request was primarily for TOP-005-1, the emphasis on such informative actions has shifted in current revision projects. The proposed IRO-010-1, Requirement R1 gives the Reliability Coordinator the right to

Standard	Source	Language	Resolution
	Interpretations of Standards from Manitoba Hydro	and include this information in its reliability assessments. The Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas." Given that Requirement R12 pre-supposes that the SPS is armed to address inter-Balancing Authority or inter-Transmission Operator impacts (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), the argument not discussed in the interpretation is that the SPS itself with one communication channel in service can be viewed for advance planning or reliability assessment purposes as a single contingency (loss of the communication channel). The question asked by the requestor indicates that the operation of the SPS on a single channel is known ahead of the timeframe for which the SPS may be armed and that the condition was not first identified when the SPS was called to operate. In this regard, the Reliability Coordinator must be aware of the less dependable state of the SPS in order to properly assess the impact and plan for the next single contingency that it conceivably could experience. In this case, the Reliability Coordinator may wish to consider the loss of an armed SPS when performing its reliability assessments. While the Reliability Coordinator may not elect to proactively position the system to withstand the loss of the SPS that is operating on a single communication channel, the Reliability Coordinator may elect to develop a contingency plan in the event the SPS does fail to operate as designed or if the remaining communication channel is lost. The importance of the SPS relative to current or anticipated system	ask for any reliability related data that they need to perform their Reliability Coordinator task. And it also mandates the Transmission Operator to provide said data in Requirement R3. (Note – This standard has been approved by the BOT but has not yet been approved by FERC.)

Standard	Source	Language	Resolution
		conditions would be considerations for the Reliability Coordinator. This consideration only becomes possible if the Transmission Operator notifies the Reliability Coordinator that the SPS is operating on a single communication channel. Therefore, Transmission Operator notification to the Reliability Coordinator of this condition raises the Reliability Coordinator's situational awareness that may influence current or future operating conditions or decisions in a preventive rather than reactive manner. NERC staff does agree that the SPS is still mission capable with only one communication channel in service, but degraded in terms of its dependability due to the unavailability of redundant communications channels. The fact that a second communications channel was part of the original design of the SPS suggests that both channels were important to the dependability of the system, and that the unavailability of either channel causes some degradation in the overall dependability of the SPS. Additionally, the team equated "any degradation" with "potential failure to operate as expected" in IRO-005. The use of the term "or" connecting these two phrases in the standard indicates these were not intended to be equivalent. Therefore, NERC staff believes the conclusion reached by the team that the two terms are synonymous is incorrect. Further, the specific circumstances contemplated in the interpretation request are not likely to occur often and the additional burden to Transmission Operators to notify the Reliability Coordinator is de minimis when compared to the improved situational awareness that would result. On this basis, NERC staff believes the interpretation is not serving the	

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Standard	Source	Language	Resolution
		best interests of reliability and should be remanded to the team for further consideration of the NERC staff opinion.	
TOP-006			
TOP-006-1	FERC Order 693	1660 & 1661 - Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system.	~~TOP-001-2, Requirements R11 through R13 cover the minimum capability issue.~~ Minimum capabilities for Transmission Operators are being handled in project 2009-02, Real-time Monitoring and Analysis Capabilities. Requirement for phase angle information is covered by proposed TOP-003-2.
TOP-006-1	FERC Order 693	1663 - Clarify the meaning of "appropriate technical information" concerning protective relays. To provide more clarity, criteria that define what "appropriate technical information" is necessary should be specified so that operators can make better informed decisions.	This term is no longer used. Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and TOP-003-2 (data).
TOP-006-1	FERC Order 693	1664 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
TOP-006-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R6 of PRC-001-1 in TOP-003 R5 or TOP-006. Note: These requirements are being retired in PRC-001-1.	See proposed TOP-003-2, Requirement R1
TOP-006-1	Version 0 Team	Need to match roles with FM	Applicability has been reviewed by the SDT and changed as required in accordance with the FM and the Compliance Registry.
TOP-006-1	Version 0 Team	Monitor frequency at multiple points	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	Load forecasting data required	New data specifications in proposed TOP-003-2 handle this concern.

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Standard	Source	Language	Resolution
TOP-006-1	Version 0 Team	GO needs to provide normal & emergency data	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R1, 1.1, 1.2 – 'available in emergency situation' may be needed	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R3 – define appropriate	This requirement was deleted as duplicative of approved PRC-001-1, Requirement R1.
TOP-006-1	VRFs Team	R4 – What information is required and what is a load pattern?	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirements R1 and R1.2, why are BAs responsible for information regarding transmission resources available for use? Isn't that the role of the TOP?	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R2, why is the BA responsible for monitoring transmission line status, voltage, load tap changer settings, and reactive power in general? Monitoring and managing reactive resources, voltage and tap settings is clearly made the responsibility of the TOP in VAR-001-1a.	Deleted – SDT agrees.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R3 why does the BA need to understand protective relaying? Isn't that the role of the TOP and GOP?	Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and proposed TOP-003-2 (data).
TOP-007			
TOP-007-0	FERC Order 693	1673 - Consider the NRC's comments on voltage requirements as part of the standards development process.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information

Standard	Source	Language	Resolution
			flowing back to the nuclear plant operator.
TOP-007-0	Version 0 Team	Need to define evidence of evaluation	This term isn't used in the requirements – no action required.
TOP-007-0	Version 0 Team	Need to tighten the non-compliance terms	Measures and VSL have been assigned to all requirements.
TOP-007-0	Version 0 Team	Not enforceable with current criteria	Not enough information provided to address concern.
TOP-007-0	Version 0 Team	RA should be included	Reliability Coordinator is now covered in Project 2006-06.
TOP-007-0	Version 0 Team	More of a compliance issue than a true standard	Not enough information provided to address concern.
TOP-008			
TOP-008-1	FERC Order 693	1681 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
PER-001			
PER-001-0	Version 0 Team	Data retention should be 1 year	This standard will be retired.

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Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001-2 – Coordination of Transmission Operations, TOP-002-3 – Operations Planning, and TOP-003-2 – Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in TOP-001-2, TOP-002-2, TOP-003-2:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric

system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eleven requirements in TOP-001-2. None of the eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, R3, R4, R7, R9, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Inability to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions: IRO-001-2 for a Reliability Coordinator and TOP-001-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is comparable to approved TOP-001-1, Requirement R6 which was assigned a High VRF so there is consistency among standards.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render emergency assistance could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-015-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities: TOP-001-2 for Transmission Operators and IRO-015-1 for Reliability Coordinators. The assignment of the Medium VRF was made based on the premise that failure to coordinate activities, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to coordinate activities. While the SDT agrees that, under some circumstances, it is possible that a failure to coordinate activities may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to coordinate would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to coordinate activities, it would still be expected to handle the situation if it occurred.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R6 has been assigned a Medium VRF and is the replacement (and a copy of) for approved TOP-003-1, Requirement R3.which was assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or cascading failures
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R7 is similar in concept to approved IRO-005-2, Requirement R3 which requires the Reliability Coordinator to act to prevent exceeding an IROL for more than 30 minutes, and approved TOP-004-2, Requirement R1 which requires the Transmission Operator to operate within SOLs and IROLs, and to approved TOP-007-0, Requirement R2 that requires that IROLs be resolved within 30 minutes all of which are assigned a High VRF so there is consistency among standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R7 mandates that entities operate within each identified IROL and its associated IROL T_v. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R8 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's

understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R9 mandates that entities operate within each identified local SOL with a 30 minute time limit. Since these are internal SOLs, bulk power system instability, separation, or cascading failures are unlikely to occur if this requirement isn't met. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, Requirements R7 and R9 which have High VRFs. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, Requirements R7, R9, and R11 and this requirement is a simple notification requirement for informational purposes only. Therefore, bulk power system instability, separation, or cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. Therefore, there is consistency among Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities act or direct others to act to mitigate the magnitude and duration of exceeding an IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

There are three requirements in TOP-002-3. None of the three requirements were assigned a "Lower" VRF. Requirement R2 was assigned a "High" VRF while Requirements R1 & R3 were given a "Medium" VRF.

VRF for TOP-002-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-008-1 that is also assigned a Medium VRF. The requirements are viewed as similar since they both refer to preparing an Operational Planning Analysis: IRO-008-1 for a Reliability Coordinator and TOP-002-3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So, while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R2 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to plan to preclude operating in violation of limits could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R3 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of their roles in mitigating potential problems does not, in and of itself, lead to bulk power system instability, separation or cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3 Requirement R3 contains only one objective, therefore only one VRF was assigned.

There are five requirements in TOP-003-2. Three of the five requirements were assigned a "Lower" VRF - Requirements R1, R2, and R3. Requirements R4 and R5 were assigned a "Medium" VRF.

VRF for TOP-003-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-010-1 that is also assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-010-1 that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-010-1 that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk

power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Low VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-010-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. However, it greatly increases the likelihood of such problems and therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-010-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. However, it greatly increases the likelihood of such problems and therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-2, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

> Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

> A violation of a "binary" type requirement must be a "Severe" VSL.
>
> Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

> VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

> . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R2. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R4. Those VSLs are also based on failure to notify reliability entities in a graduated scale from Lower to Severe. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the proposed IRO-014-2, Requirement R1. Those VSLs are also based on a graduated scale from Lower to Severe. The VSLs assignments are similar between the two standards. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination and Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-002-3 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in proposed IRO-008-1, Requirement R1. That VSL is not binary as is the one proposed for this requirement. It proposes a graduated situation based on a number of days missing from the analysis. In looking at the VSL for this requirement, the SDT decided that it was an all or nothing situation – one either did the proper analysis or it didn't.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		Therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-002-3 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The proposed requirement is new and there are no comparable VSLs. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-002-3 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed IRO-010-1, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed IRP-010-1, Requirement R2. The proposed VSLs both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed IRO-010-1, Requirement R2. The proposed VSLs both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to proposed IRO-010-1, Requirement R3 which employs an incremental VSL.. However, in this case, the SDT decided that this requirement was more binary in nature and has only suggested a severe VSL Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001-2 ~~—~~– Coordination of Transmission Operations, TOP-002-3 ~~—~~– Operations Planning, and TOP-003-2 ~~—~~– Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of ~~VRF~~Violation Risk Factors in TOP-001-2, TOP-002-2,~~ and~~ TOP-003-2:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric

system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are ~~thirteen~~eleven requirements in TOP-001-2. None of the ~~thirteen~~eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, R3, R4, ~~R8~~R7, R9, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Inability to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R4) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions: IRO-001-2 for a Reliability Coordinator and TOP-001-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is comparable to approved TOP-001-1, Requirement R6 which was assigned a ~~new requirement,~~High VRF so there ~~are no comparable requirements in other~~is consistency among standards ~~with which to compare VRFs~~.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render emergency assistance could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-~~014-2~~015-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities: TOP-001-2 for Transmission Operators and IRO-~~014-2~~015-1 for Reliability Coordinators. The assignment of the Medium VRF was made based on the premise that failure to coordinate activities, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to coordinate activities. While the SDT agrees that, under some circumstances, it is possible that a failure to coordinate activities may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to coordinate would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to coordinate activities, it would still be expected to handle the situation if it occurred.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement ~~R7~~R6 has been assigned a Medium VRF and is the replacement (and a copy of) for approved TOP-003-1, Requirement R3.which was assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or cascading failures

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement ~~R7~~R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- ~~FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.~~

~~FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.~~

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R7 is similar in concept to approved IRO-005-2, Requirement R3 which requires the Reliability Coordinator to act to prevent exceeding an IROL for more than 30 minutes, and approved TOP-004-2, Requirement R1 which requires the Transmission Operator to operate within SOLs and IROLs, and to approved TOP-007-0, Requirement R2 that requires that IROLs be resolved within 30 minutes all of which are assigned a High VRF so there is consistency among standards.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement ~~R8~~R7 mandates that entities operate within each identified IROL and its associated IROL T_v. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. ~~TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.~~TOP-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs. ~~FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.~~

- ~~FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.~~

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement ~~R9~~R8 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement ~~R8~~R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.~~TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.~~

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VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R9 mandates that entities operate within each identified local SOL with a 30 minute time limit. Since these are internal SOLs, bulk power system instability, separation, or cascading failures are unlikely to occur if this requirement isn't met. Therefore, this requirement was assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, ~~Requirement R8 which has a High VRF. If the Transmission Operator failed to notify the Reliability Coordinator of actions to alleviate a specific SOL that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R8.~~Requirements R7 and R9 which have High VRFs. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, ~~Requirement R8~~Requirements R7, R9, and R11 and this requirement is a simple notification requirement for informational purposes only. Therefore, bulk power system instability, separation, or cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.

- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R1~~0~~1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. Therefore, there is consistency among Reliability Standards.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities ~~operate within each identified~~act or direct others to act to mitigate the magnitude and duration of exceeding an IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

~~VRF for TOP-001-2, Requirement R11:~~

- ~~FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.~~

- ~~FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved IRO-002-1, Requirement R8 which has a High VRF. Therefore, there is consistency among Reliability Standards.~~

- ~~FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that a Transmission Operator shall monitor the conditions and Facilities within its Transmission Operator Area. By definition, if an entity fails to do so,~~

~~bulk power system instability, separation, or cascading failures are more likely to occur. Therefore, this requirement was assigned a High VRF.~~

- ~~FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.~~

~~VRF for TOP-001-2, Requirement R12:~~

- ~~FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.~~
- ~~FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R12 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved IRO-001-1, Requirement R8 which has a High VRF. Therefore, there is consistency among Reliability Standards.~~
- ~~FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that a Transmission Operator shall monitor the conditions and Facilities external its Transmission Operator Area subject to certain constraints. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are more likely to occur. Therefore, this requirement was assigned a High VRF.~~
- ~~FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R12 addresses a single objective and has a single VRF.~~

~~VRF for TOP-001-2, Requirement R13:~~

- ~~FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.~~
- ~~FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R13 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved IRO-002-1, Requirement R9 which has a Medium VRF. Therefore, there is consistency among Reliability Standards.~~
- ~~FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R13 mandates that entities have control over planned outages of their monitoring and analysis capabilities. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are unlikely to occur. Therefore, this requirement was assigned a Medium VRF.~~
- ~~FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R13 addresses a single objective and has a single VRF.~~

There are three requirements in TOP-002-3. None of the three requirements were assigned a "Lower" VRF. Requirement R2 was assigned a "High" VRF while Requirements R1 & R3 were given a "Medium" VRF.

VRF for TOP-002-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-008-1 that is also assigned a Medium VRF. The requirements are viewed as similar since they both refer to preparing an Operational Planning Analysis: IRO-008-1 for a Reliability Coordinator and TOP-002-3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So, while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict. ~~FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.~~
- ~~FERC's Guideline 3 — Consistency among Reliability Standards.~~
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R2 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to plan to preclude operating in violation of limits could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. ~~FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.~~
- ~~FERC's Guideline 3 — Consistency among Reliability Standards.~~ TOP-002-3, Requirement R3 is a new requirement, so there are no comparable requirements with which to compare VRFs.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of their roles in mitigating potential problems does not, in and of itself, lead to bulk power system instability, separation or cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3 Requirement R3 contains only one objective, therefore only one VRF was assigned.

There are five requirements in TOP-003-2. Three of the five requirements were assigned a "Lower" VRF - Requirements R1, R2, and R3. Requirements R4 and R5 were assigned a "Medium" VRF.

VRF for TOP-003-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-010-1 that is also assigned a Low VRF. The requirements are viewed as similar since they both refer to data specifications: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-010-1 that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-010-1 that is assigned a Low VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Low VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-010-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or

cascading failures. However, it greatly increases the likelihood of such problems and therefore, this requirement is assigned a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-010-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator and Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. However, it greatly increases the likelihood of such problems and therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

Justification for Assignment of ~~VSLs~~Violation Severity Levels for TOP-001-2, TOP-002-2, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

> Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

> A violation of a "binary" type requirement must be a "Severe" VSL.
>
> Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

> VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

> . . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~ ~~Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance~~	~~Guideline 2~~ ~~Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties~~ ~~Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent~~ ~~Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language~~	~~Guideline 3~~ ~~Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement~~	~~Guideline 4~~ ~~Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations~~

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R2. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R4. Those VSLs are also based on failure to notify reliability entities in a graduated scale from Lower to Severe. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R4:

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~	~~Guideline 2~~	~~Guideline 3~~	~~Guideline 4~~
~~R3.~~ R#	~~Meets~~Compliance with NERC's VSL Guidelines~~ – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.~~	~~The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R4. These VSLs are also based on failure to notify reliability entities in a graduated scale from Lower to Severe. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.~~Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	~~The proposed VSLs do not use any ambiguous terminology, thereby supporting~~Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of ~~similar penalties~~Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for ~~similar violations.~~"Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	~~The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore,~~Guideline 3 Violation Severity Level Assignment Should Be Consistent with the ~~requirement.~~Corresponding Requirement	~~The VSLs are~~Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation ~~and not cumulative violations.~~, Not on A Cumulative Number of Violations

~~**VSLs for TOP-001-2 Requirement R4:**~~

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~	~~Guideline 2~~	~~Guideline 3~~	~~Guideline 4~~
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the proposed IRO-014-2, Requirement R1. Those VSLs are also based on a graduated scale from Lower to Severe. The VSLs assignments are similar between the two standards. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's Revised VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R7:

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~	~~Guideline 2~~	~~Guideline 3~~	~~Guideline 4~~
R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~	~~Guideline 2~~	~~Guideline 3~~	~~Guideline 4~~
~~R8.~~	~~Meets NERC's VSL guidelines.~~	~~The proposed requirement is new and there are no comparable VSLs.~~	~~The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~	~~The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.~~	~~The VSL is based on a single violation and not cumulative violations.~~

~~**VSLs for TOP-001-2 Requirement R9:**~~

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
~~R9~~R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with	The VSL is based on a single violation and not cumulative violations.

	violation and the VSLs follow the guidelines for incremental violations.		violations.	the requirement.	

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination and Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
~~R10~~R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-~~001-2~~002-3 Requirement ~~R11~~R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
~~R11~~R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	~~The proposed~~ There is a similar requirement ~~is new and there are no comparable VSLs but it is similar to approved~~ in proposed IRO-~~002~~008-1, Requirement ~~R8~~R1. That ~~is a multiple part requirement but the~~ VSL ~~for the part dealing with monitoring is~~is not binary as is the one proposed for this ~~new~~ requirement. It proposes a graduated situation based on a number of days missing from the analysis. In	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		looking at the VSL for this requirement~~.~~, the SDT decided that it was an all or nothing situation – one either did the proper analysis or it didn't. Therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-002-3 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The proposed requirement is new and there are no comparable VSLs. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-~~001-2~~002-3 Requirement ~~R12~~R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
~~R12~~R3.	Meets NERC's VSL guidelines - ~~Severe: Missing most or all of~~There is an incremental aspect to the ~~significant elements (or a significant percentage) of~~violation and the ~~required performance~~VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs~~ but it is similar to approved IRO-002-1, Requirement R8. That is a multiple part requirement but the VSL for the part dealing with monitoring is binary as is the one proposed for this new requirement.~~ Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		already proposed.			

VSLs for TOP-~~001~~003-2 Requirement ~~R13:~~

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~	~~Guideline 2~~	~~Guideline 3~~	~~Guideline 4~~
~~R13.~~	~~Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.~~	~~The proposed requirement is new and there are no comparable VSLs but it is similar to approved IRO-002-1, Requirement R9. That VSL is incremental. However, the SDT felt that this requirement, while similar but not exactly the same, warranted a binary VSL. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.~~	~~The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~	~~The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.~~	~~The VSL is based on a single violation and not cumulative violations.~~

~~VSLs for TOP-002-3 Requirement~~ R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

			Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language		
R1.	Meets NERC's VSL guidelines - ~~Severe: Missing most or all of~~There is an incremental aspect to the ~~significant elements (or a significant percentage) of~~violation and the ~~required performance~~VSLs follow the guidelines for incremental violations.	~~There is a similar~~ The proposed requirement ~~in~~ is similar to proposed IRO-~~008~~010-1, Requirement R1. ~~That VSL is not binary as is the one~~The proposed ~~for this requirement. It proposes~~VSLs are similar in that they build on a graduated ~~situation~~scale based on ~~a number of days~~ missing ~~from the analysis. In looking at the VSL for this requirement, the SDT decided that it was an all or nothing situation – one either did the proper analysis or it didn't. Therefore, it decided that the VSL for this requirement should be binary~~parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-~~002-3~~003-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - ~~Severe: Missing most or all of~~There is an incremental aspect to the ~~significant elements (or a significant percentage) of~~violation and the ~~required performance~~VSLs follow the guidelines for incremental violations.	The proposed requirement is ~~new and there are no comparable~~similar to proposed IRP-010-1, Requirement R2. The proposed VSLs~~.~~ both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-~~002-3~~003-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is ~~new and there are no comparable~~similar to proposed IRO-010-1, Requirement R2. The proposed VSLs both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement ~~R1~~R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
~~R1~~R4.	Meets NERC's VSL guidelines - ~~There is an incremental aspect to~~Severe: Missing most or all of the ~~violation and~~significant elements (or a significant percentage) of the ~~VSLs follow the guidelines for incremental violations~~required performance.	The proposed requirement is similar to proposed IRO-010-1, Requirement ~~R1. The proposed VSLs are similar~~R3 which employs an incremental VSL.. However, in this case, the SDT decided that ~~they build on a graduated scale based on missing parts of the~~ this requirement~~.~~ was more binary in nature and has only suggested a severe VSL Thus, the VSL in the proposed standard does not lower the level	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		of compliance currently required by setting VSLs that are less punitive than those already proposed.			

~~VSLs for TOP-003-2 Requirement R2:~~

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~	~~Guideline 2~~	~~Guideline 3~~	~~Guideline 4~~
~~R2.~~	~~Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.~~	~~The proposed requirement is similar to proposed IRP-010-1, Requirement R2. The proposed VSLs both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.~~	~~The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~	~~The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.~~	~~The VSL is based on a single violation and not cumulative violations.~~

~~VSLs for TOP-003-2 Requirement R3:~~

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~	~~Guideline 2~~	~~Guideline 3~~	~~Guideline 4~~
~~R3.~~	~~Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the~~	~~The proposed requirement is similar to proposed IRO-010-1, Requirement R2. The proposed VSLs both build on 5% increments towards the Severe level.~~	~~The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~	~~The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.~~	~~The VSL is based on a single violation and not cumulative violations.~~

	~~guidelines for incremental violations.~~	~~Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.~~			

~~VSLs for TOP-003-2 Requirement R4:~~

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~	~~Guideline 2~~	~~Guideline 3~~	~~Guideline 4~~
~~**R4.**~~	~~Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.~~	~~The proposed requirement is similar to proposed IRO-010-1, Requirement R3. The proposed VSLs both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.~~	~~The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~	~~The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.~~	~~The VSL is based on a single violation and not cumulative violations.~~

~~VSLs for TOP-003-2 Requirement R5:~~

~~R#~~	~~Compliance with NERC's VSL Guidelines~~	~~Guideline 1~~	~~Guideline 2~~	~~Guideline 3~~	~~Guideline 4~~
~~**R5.**~~	~~Meets NERC's~~	~~The proposed~~	~~The proposed VSL does not use~~	~~The proposed VSL uses the~~	~~The VSL is based on~~

	~~VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.~~	~~requirement is similar to proposed IRO-010-1, Requirement R3. The proposed VSLs both build on 5% increments towards the Severe level. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.~~	~~any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~	~~same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.~~	~~a single violation and not cumulative violations.~~

A. Introduction

1. Title: **Operating Personnel Responsibility and Authority**

2. Number: PER-001-0.1

3. Purpose: Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. Applicability

4.1. Transmission Operators.

4.2. Balancing Authorities.

5. Effective Date: December 10, 2009

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The job description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0.1	April 15, 2009	Replaced “position” with “job” on M1.1	Errata
0.1	December 10, 2009	Approved by FERC — added effective date	Update

A. Introduction

1. Title: **Reliability Responsibilities and Authorities**

2. Number: TOP-001-1

Purpose: To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

3. Applicability

3.1. Balancing Authorities

3.2. Transmission Operators

3.3. Generator Operators

3.4. Distribution Providers

3.5. Load Serving Entities

4. Effective Date: January 1, 2007

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:

R7.1. For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.2. For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.3. When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

C. Measures

M1. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.

M2. If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)

M3. Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)

M4. Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or

statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)

M5. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

M6. The Transmission Operator, Balancing Authority, and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)

M7. The Transmission Operator and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Balancing Authority:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

2.4.2 Did not render emergency assistance to others as requested, in accordance with R6.

3. Levels of Non-Compliance for a Transmission Operator

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Does not have the documented authority to act as specified in R1.

3.4.2 Does not have evidence it acted with the authority specified in R1.

3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.

3.4.4 Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.

3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.

3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.

3.4.7 Did not render emergency assistance to others as requested, as specified in R6.

3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

4. Levels of Non-Compliance for a Generator Operator:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.

4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.

4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity

5.1. Level 1: Not applicable.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable

5.4. Level 4: Did not comply with a Transmission Operator's reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Normal Operations Planning**

2. **Number:** TOP-002-2a

3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

   4.3. Generator Operator.

   4.4. Load Serving Entity.

   4.5. Transmission Service Provider.

5. **Effective Date:** Immediately after approval of applicable regulatory authorities. FERC Approved 12/2/09

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)

R14.1. Changes in real output capabilities. (Effective August 1, 2007)

R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance for Balancing Authorities:**

   2.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

   2.2. **Level 2:** Not applicable.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4**: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

      2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. **Levels of Non-Compliance for Transmission Operators**

   3.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

   3.2. **Level 2:** Not applicable.

   3.3. **Level 3:** One or more of Bulk Electric System studies were not made available as specified in R11.

   3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

      3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

      3.4.3 Studies not updated to reflect current system conditions as specified in R11.

      3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. **Levels of Non-Compliance for Generator Operators:**

   4.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

   4.2. **Level 2:** Not applicable.

   4.3. **Level 3:** Not applicable.

   4.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

      4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

      4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. **Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:**

   5.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation

Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a "unique" study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have "a" study that can be applied to it, but it is not necessary to generate a "unique" study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a "study"? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, "to determine SOLs" as used in the first sentence of Requirement R11 mean the "determination of system operating limits" or does it mean the "identification of potential SOL violations?"

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential "exceedances" of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.

A. Introduction

1. **Title:** **Planned Outage Coordination**

2. **Number:** TOP-003-1

3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

4. **Applicability**

   4.1. Generator Operators.

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

   4.4. Reliability Coordinators.

5. **Proposed Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information.

R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.

R1.2. Each Transmission Operator shall provide outage information daily to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.

R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, and Balancing Authority reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to "not be taken" because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Generator Operator failed to provide outage information, in accordance with its Transmission Operators established outage reporting requirements, to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW).
R1.1	N/A	N/A	N/A	The Transmission Operator failed to provide outage information, in accordance with its Reliability Coordinators established outage reporting requirement, to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.
R1.2	The responsible entity failed to provide the information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	N/A	N/A	N/A

R#	Lower	Moderate	High	Severe
R1.3	N/A	N/A	N/A	The responsible entity failed to plan or coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators when required.
R2	The responsible entity planned and coordinated scheduled outages of telemetering and control equipment and associated communication channels with its Reliability Coordinator, but failed to coordinate with affected neighboring Transmission Operators, Balancing Authorities, and Generator Operators.	N/A	N/A	The responsible entity failed to plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
R3	N/A	N/A	N/A	The Reliability Coordinator failed to resolve any scheduling of potential reliability conflicts.
R4	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 30 minutes but less than or equal to 35 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 35 minutes but less than or equal to 40 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 40 minutes but less than or equal to 45 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 45 minutes.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 23, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	

A. Introduction

1. **Title:** **Transmission Operations**

2. **Number:** TOP-004-2

3. **Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.

4. **Applicability:**

   4.1. Transmission Operators

5. **Proposed Effective Date:** Twelve months after BOT adoption of FAC-014.

B. Requirements

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.

R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.

R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

R6.1. Monitoring and controlling voltage levels and real and reactive power flows.

R6.2. Switching transmission elements.

R6.3. Planned outages of transmission elements.

R6.4. Responding to IROL and SOL violations.

C. Measures

M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.

M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data for Measure 1.

Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.

2.3. .**Level 3:** Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.

2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata

A. Introduction

1. **Title:** **Operational Reliability Information**

2. **Number:** TOP-005-2

3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Purchasing Selling Entities.

5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

   Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.
R2	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.
R3	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Removed the Reliability Coordinator from the list of responsible functional entities Deleted R1 and R1.1 Modified M1 to omit the reference to the Reliability Coordinator Deleted VSLs for R1 and R1.1	Revised
2	March 23, 2011	Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)	

Attachment 1-TOP-005

Electric System Reliability Data

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

1. The following information shall be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

1.1.1 Status.

1.1.2 MW or ampere loadings.

1.1.3 MVA capability.

1.1.4 Transformer tap and phase angle settings.

1.1.5 Key voltages.

1.2. Generator data.

1.2.1 Status.

1.2.2 MW and MVAR capability.

1.2.3 MW and MVAR net output.

1.2.4 Status of automatic voltage control facilities.

1.3. Operating reserve.

1.3.1 MW reserve available within ten minutes.

1.4. Balancing Authority demand.

1.4.1 Instantaneous.

1.5. Interchange.

1.5.1 Instantaneous actual interchange with each Balancing Authority.

1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.

1.5.3 Interchange Schedules for the next 24 hours.

1.6. Area Control Error and frequency.

1.6.1 Instantaneous area control error.

1.6.2 Clock hour area control error.

1.6.3 System frequency at one or more locations in the Balancing Authority.

2. Other operating information updated as soon as available.

2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.

2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.

2.3. Forecast peak demand for current day and next day.

2.4. Forecast changes in equipment status.

2.5. New facilities in place.

2.6. New or degraded special protection systems.

2.7. Emergency operating procedures in effect.

2.8. Severe weather, fire, or earthquake.

2.9. Multi-site sabotage.

A. Introduction

1. **Title:** **Monitoring System Conditions**

2. **Number:** TOP-006-2

3. **Purpose:** To ensure critical reliability parameters are monitored in real-time.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Operators.

   4.4. Reliability Coordinators.

5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.

R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

C. Measures

M1. The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. (Requirement 1.2)

M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.

M4. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system's near-term load pattern. (Requirement 4)

M5. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)

M6. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift-operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measure 2.

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure 3, 5 and 6.

Each Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity failed to know the status of all generation and transmission resources available for use, even though said information was reported by the Generator Operator, Transmission Operator, or Balancing Authority.
R1.1	N/A	N/A	N/A	The Generator Operator failed to inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
R1.2	N/A	N/A	N/A	The responsible entity failed to inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
R2	N/A	The responsible entity monitors the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, but is not aware of the status of rotating and static reactive resources.	The responsible entity fails to monitor all of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of all rotating and static reactive resources.	The responsible entity fails to monitor any of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
R3	The responsible entity failed to provide any of the appropriate technical information concerning protective relays to their operating personnel.	N/A	N/A	The responsible entity failed to provide all of the appropriate technical information concerning protective relays to their operating personnel.

R#	Lower	Moderate	High	Severe
R4	N/A	N/A	The responsible entity has either weather forecasts or past load patterns, available to predict the system's near-term load pattern, but not both.	The responsible entity failed to have both weather forecasts and past load patterns, available to predict the system's near-term load pattern.
R5	N/A	N/A	The responsible entity used monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions, but does not have indication of the need for corrective action.	The responsible entity failed to use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions.
R6	N/A	N/A	N/A	The responsible entity failed to use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
R7	N/A	N/A	N/A	The responsible entity failed to monitor system frequency.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Modified R4 Modified M4 Modified Data Retention for M4 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	
2	March 23, 2011	Order issued by FERC approving TOP-006-2 (approval effective 5/23/11)	

A. Introduction

1. **Title:** Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations

2. **Number:** TOP-007-0

3. **Purpose:**

   This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.

R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.

R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.

R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

C. Measures

M1. Evidence that the Transmission Operator informed the Reliability Coordinator when an IROL or SOL was exceeded and the actions taken to return the system to within limits.

M2. Evidence that the Transmission Operator returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.

M3. Evidence that the Reliability Coordinator evaluated actions and provided direction required to return the system to within limits.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   The Reliability Coordinator shall report any IROL violation exceeding 30 minutes to the Regional Reliability Organization and NERC within 72 hours. Each Regional Reliability Organization shall report any such violations to NERC via the NERC compliance reporting process. The Reliability Coordinator shall report any SOL violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:

1.1.1. System instability.

1.1.2. Unacceptable system dynamic response or equipment tripping.

1.1.3. Voltage levels in violation of applicable emergency limits.

1.1.4. Loadings on transmission facilities in violation of applicable emergency limits.

1.1.5. Unacceptable loss of load based on regional and/or NERC criteria.

1.2. Compliance Monitoring Period and Reset Timeframe

The reset period is monthly.

1.3. Data Retention

The data retention period is three months.

2. Levels of Non-Compliance

2.1. The Transmission Operator did not inform the Reliability Coordinator of an IROL or an SOL that has become an IROL because of changed system conditions, and the actions they are taking to return the system to within limits, or

2.2. The Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the system to within the IROL within 30 minutes. (See Table 1-TOP-007-0 below.)

2.3. The limit violation was reported to the Reliability Coordinator, who did not provide appropriate direction to the Transmission Operator, resulting in an IROL violation in excess of 30 minutes duration.

Table 1-TOP-007-0 IROL and SOL Reporting Levels of Non-Compliance

Percentage by which IROL or SOL that has become an IROL is exceeded*	Limit exceeded for more than 30 minutes, up to 35 minutes.	Limit exceeded for more than 35 minutes, up to 40 minutes.	Limit exceeded for more than 40 minutes, up to 45 minutes.	Limit exceeded for more than 45 minutes.
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

*Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Response to Transmission Limit Violations**

2. **Number:** TOP-008-1

3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.

4. **Applicability**

   4.1. Transmission Operators.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.

R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

C. Measures

M1. The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)

M2. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1

M3. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)

M4. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents,

copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)

M5. The Transmission Operator that violates an SOL shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.

Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Transmission Operator

2.1. Level 1: Not applicable.

2.2. Level 2: Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.

2.4.2 Did not disconnect an overloaded facility as specified in R3.

2.4.3 Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)

2.4.4 Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

Comment Form for 5th Draft of Standards for Real-Time Operations (Project 2007-03)

Comments on the 5th draft and initial ballot of the standards for Real-Time Operations (Project 2007-03) **must be submitted by June 9, 2011.** If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information:

In the 5th posting for Project 2007-03, the Real-Time Operations Standard Drafting Team (RTOSDT) has attempted to clarify the proposed changes to the TOP family of standards based on industry comments received for the 4th posting and suggestions made during the Quality Review. Changes made were:

TOP-001-2:

- Update to the definition of Reliability Directive based on the efforts of Project 2006-06 which is responsible for the content of the definition
- Clarification to Requirement R2 that it is an 'identified' Reliability Directive that is in question. Plus, the Time Horizon was adjusted to add 'Operations Planning'.
- Grammatical change to Requirement R3 changing 'of' to 'by'.
- Grammatical change to Requirements R5 and R6 to eliminate the use of 'coordinate'.
- Change 'local' area reliability to 'internal' area reliability in Requirement R8.
- Change the VRF for Requirement R9 from High to Medium.
- Clarification in Requirement R11 that 30 minutes is the timeframe for the indicated SOLs.
- Deleted Requirements R12 & R13 as they will be covered in Project 2009-02.
- Corresponding wording changes were made to the Measures and VSLs to match the revised wording in the Requirements.
- Fix a typo in Measure M10.
- Updated the Compliance Enforcement Authority language.
- Fixed the language in the VSL for Requirement R3 to match the actual requirement language.
- Clarify the intent of the SDT with regard to the VSL for Requirement R5.

TOP-002-3:

- Adjusted the Purpose Statement.
- Clarification to the rationale provided for Requirement R1.
- Made grammatical changes to Requirement R2 and updated 'local' to 'internal' as per TOP-001-2.
- Changed 'reliability' to 'registered' in Requirement R3.
- Added 'while not an IROL' to Measure M2.
- Made corresponding language changes to the Measures and VSLs to match the language changes in the Requirements.
- Updated the Compliance Enforcement Authority language.
- Clarified the intent of the SDT with regard to the VSL for Requirement R3.

TOP-003-1:

- Grammatical changes to Requirement R1.
- Added 'Transmission Operator' to Requirement R4 and eliminated Requirement R5.
- Added 'web postings' to Measures M2 and M3.
- Clarified Measure M4.
- Updated the Compliance Enforcement Authority language.
- Eliminated a redundancy in the VSL for Requirement R2.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☐ No

   Comments:

3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

☐ Yes

☐ No

Comments:

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. Do you support the proposed VRF. VSL and Time Horizon assignments?

   If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☐ No

   Comments:

5. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.

   Comments:

Standards Announcement

Project 2007-03 Real-time Operations
Ballot Pool Window Open April 26 – May 25, 2011
Formal Comment Period Open April 26 – June 9, 2011
Initial Ballot and Non-Binding Poll of VRFs and VSLs May 31 – June 9, 2011

Now available at:
http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

The Real-time Operations Standards Drafting Team has made revisions to three standards and their associated implementation plan in response to stakeholder comments and a quality review:

- TOP-001-2 Coordination of Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Clean and redline versions of these standards and the associated implementation plan and VRFs and VSLs, are posted for a 45-day comment period through Thursday, June 9, 2011.

Note that TOP-001-2, TOP-002-3, and TOP-3-2 reflect the merging of the following standards into a single standard, making it impractical to post a "redline" of the three proposed standards that shows the changes to the last balloted versions of those standards. The last approved versions of the standards listed below have been posted on the project's web page for easy reference.

- PER-001-0 Operating Personnel Responsibility and Authority
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-1 Response to Transmission Violations

During the first 30 days of this period, a new ballot pool is being formed for balloting these standards.

Instructions for Joining the Ballot Pool for Project 2007-03

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2007-03_RTO_in@nerc.com

Members who join the ballot pool to vote on the standard will automatically be entered in a separate pool to participate in the non-binding poll of the associated violation risk factor (VRF) and violation severity levels (VSLs).

Instructions for Submitting Comments

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page: http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit two separate sets of comments (one during the comment period and a second with a ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders only provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

Next Steps

A concurrent ballot of the three standards and the associated implementation plan, and non-binding poll of the associated VRFs and VSLs will begin on Tuesday, May 31 through Thursday, June 9, 2011.

Project Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-03 Real-time Operations
Initial Ballot and Non-binding Poll Results

Now available at: https://standards.nerc.net/Ballots.aspx

An initial ballot of three standards, TOP-001-2 Coordination of Transmission Operations, TOP-002-2 Operations Planning, and TOP-003-2 Operational Reliability Data, and a concurrent non-binding poll of associated VRFs and VSLs, concluded on June 9, 2011.

Ballot Results for TOP-001-2, TOP-002-2, and TOP-003-2

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 88.47%
Approval: 48.64%

Non-binding Poll Results for Associated VRF and VSLs

Of those who registered to participate, 84.18% provided an opinion or an abstention; 41% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Next Steps

The drafting team will consider all comments received during the formal comment period, ballot, and non-binding poll, and will determine whether to make additional changes to the standards, implementation plan, and associated VRFs and VSLs. If the team makes substantive changes to address issues raised in comments, the standards will be submitted for quality review prior to being posted for an additional 30-day formal comment period with a successive ballot during the last ten days of the comment period.

Background

The drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. TOP-001-2, TOP-002-2, and TOP-003-2 merge requirements from the following standards:

- PER-001-0 Operating Personnel Responsibility and Authority
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions

• TOP-007-0 Reporting Sol and IROL Violations

• TOP-008-1 Response to Transmission Violations

Additional information is available on the project web page at http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html.

Standards Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Ballot Results	
Ballot Name:	Project 2007-03 Real-time Operations April 2011_in
Ballot Period:	5/31/2011 - 6/9/2011
Ballot Type:	Initial
Total # Votes:	330
Total Ballot Pool:	373
Quorum:	88.47 % The Quorum has been reached
Weighted Segment Vote:	48.64 %
Ballot Results:	The standard will proceed to recirculation ballot.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	48	0.571	36	0.429	7	12
2 - Segment 2.	11	0.9	1	0.1	8	0.8	0	2
3 - Segment 3.	82	1	37	0.552	30	0.448	7	8
4 - Segment 4.	27	1	8	0.4	12	0.6	1	6
5 - Segment 5.	82	1	38	0.559	30	0.441	6	8
6 - Segment 6.	47	1	24	0.615	15	0.385	4	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.7	3	0.3	4	0.4	0	1
9 - Segment 9.	4	0.3	1	0.1	2	0.2	0	1
10 - Segment 10.	9	0.7	5	0.5	2	0.2	1	1
Totals	**373**	**7.6**	**165**	**3.697**	**139**	**3.903**	**26**	**43**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	View
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	View
1	Avista Corp.	Scott Kinney	Affirmative	
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	View

1	BC Hydro and Power Authority	Patricia Robertson	Negative	View
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	CenterPoint Energy Houston Electric	Dale G Bodden	Negative	
1	Central Maine Power Company	Kevin L Howes	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	View
1	City of Vero Beach	Randall McCamish	Negative	View
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	View
1	Empire District Electric Co.	Ralph Frederick Meyer		
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Grand River Dam Authority	James M Stafford	Negative	View
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	View
1	JEA	Ted E Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stan T. Rzad	Negative	
1	Lake Worth Utilities	Walt J Gill	Abstain	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	Ly M Le	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	Muscatine Power & Water	Tim Reed	Negative	View
1	National Grid	Saurabh Saksena	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	View
1	New York Power Authority	Arnold J. Schuff	Negative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Negative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	View

1	Potomac Electric Power Co.	David Thorne	Affirmative	View
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Negative	View
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	View
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	View
1	Raj Rana	Rajendrasinh D Rana	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Negative	View
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Robert A Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Negative	View
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Mark B Thompson	Negative	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Negative	View
2	California ISO	Richard K Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning		
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Negative	View
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Negative	View
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R. Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	View
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clatskanie People's Utility District	Brian Fawcett	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Lisa Cleary	Negative	View
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Constellation Energy	Carolyn Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	View
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	José H Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	

3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources Services	Michael F Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	East Kentucky Power Coop.	Sally Witt	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Power and Light / NextEra Energy	Chantel Haswell	Abstain	
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	View
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	View
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace Hunter	Negative	View
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	View
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	View
3	PacifiCorp	John Apperson	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	View
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Affirmative	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	View
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	View
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	View
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	View
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	View
4	Consumers Energy	David Frank Ronk	Negative	View

4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring	Negative	View
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	View
4	Imperial Irrigation District	Diana U Torres		
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Negative	View
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Negative	View
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Negative	View
5	City of Redding	Paul A Cummings	Affirmative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	View
5	City of Tallahassee	Brian Horton	Affirmative	View
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Negative	View
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton		
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	View
5	Green Country Energy	Greg Froehling	Affirmative	
5	I do not represent an Entity	Bruce Paggeot	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Jim M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	View
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	View
5	Manitoba Hydro	S N Fernando	Affirmative	View

5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson	Affirmative	
5	New York Power Authority	Gerald Mannarino	Negative	
5	Northern Indiana Public Service Co.	William O Thompson	Negative	
5	Occidental Chemical	Michelle DAntuono	Negative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Negative	
5	PSEG Fossil LLC	Mikhail Falkovich	Negative	View
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Negative	View
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Affirmative	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Negative	View
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	View
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	View
6	Dominion Resources, Inc.	Louis S. Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	View
6	NRG Energy, Inc.	Alan R. Johnson	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Affirmative	

6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Negative	View
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	View
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Abstain	
6	Santee Cooper	Suzanne Ritter	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Benjamin Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	View
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		James A Maenner	Negative	View
8		Roger C Zaklukiewicz	Negative	View
8		Merle Ashton		
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Negative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	View
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D. Grimm	Affirmative	View
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Ballot Results	
Non-Binding Poll Name:	Project 2007-03 RTO non-binding poll VRFs and VSLs
Poll Period:	5/31/2011 - 6/9/2011
Total # Opinions:	222
Total Ballot Pool:	373
Summary Results:	84.18% of those who registered to participate provided an opinion or abstention; 41% of those who provided an opinion indicated support for the VRFs and VSL.

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert D Smith	Negative	View
1	Associated Electric Cooperative, Inc.	John Bussman	Abstain	
1	Avista Corp.	Scott Kinney	Negative	View
1	Balancing Authority of Northern California NCR11118	Kevin Smith	Abstain	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge	Negative	View
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	CenterPoint Energy Houston Electric	Dale G Bodden	Negative	

1	Central Maine Power Company	Kevin L Howes	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	View
1	City of Vero Beach	Randall McCamish	Negative	View
1	Clark Public Utilities	Jack Stamper	Negative	View
1	Cleco Power LLC	Danny McDaniel		
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph Frederick Meyer		
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Abstain	
1	Georgia Transmission Corporation	Harold Taylor, II	Abstain	
1	Grand River Dam Authority	James M Stafford	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier		

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	Imperial Irrigation District	Tino Zaragoza	Negative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	View
1	JEA	Ted E Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Keys Energy Services	Stan T. Rzad	Negative	
1	Lake Worth Utilities	Walt J Gill	Abstain	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath	Abstain	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	Ly M Le	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Abstain	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	Muscatine Power & Water	Tim Reed		
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Arnold J. Schuff	Negative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David H. Boguslawski	Affirmative	

1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Negative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Negative	View
1	PacifiCorp	Colt Norrish	Abstain	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji		
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman	Negative	View
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Negative	View
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	View
1	Raj Rana	Rajendrasinh D Rana	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	

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1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Robert A Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Abstain	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	View
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Richard K Vine	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning		

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2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Abstain	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Negative	View
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	View
3	City of Farmington	Linda R. Jacobson	Negative	View
3	City of Garland	Ronnie C Hoeinghaus	Negative	View
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clatskanie People's Utility District	Brian Fawcett	Abstain	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Lisa Cleary	Negative	View

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3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Constellation Energy	Carolyn Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	José H Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	
3	East Kentucky Power Coop.	Sally Witt	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Power and Light / NextEra Energy	Chantel Haswell	Abstain	
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N Phinney	Abstain	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	View
3	Imperial Irrigation District	Jesus S. Alcaraz	Negative	View
3	JEA	Garry Baker	Affirmative	

3	Kansas City Power & Light Co.	Charles Locke		
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Negative	View
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Negative	View
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	View
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Negative	View
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	
3	Pacific Gas and Electric Company	John H Hagen	Negative	View
3	PacifiCorp	John Apperson	Abstain	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters		
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	

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3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Negative	View
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Negative	View
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Negative	View
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Negative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini		
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	

4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews		
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres		
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Negative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	AES Corporation	Leo Bernier	Affirmative	View
5	Amerenue	Sam Dwyer	Negative	

5	Arizona Public Service Co.	Edward Cambridge	Negative	View
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Negative	View
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale		
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul A Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	View
5	City of Tallahassee	Brian Horton	Abstain	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Negative	View
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton		
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North	Dana Showalter	Abstain	

	America, LLC			
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	
5	Green Country Energy	Greg Froehling	Abstain	
5	I do not represent an Entity	Bruce Paggeot	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Negative	View
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	Jim M Howard	Abstain	
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Negative	View
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider		
5	Muscatine Power & Water	Mike Avesing	Negative	

5	Nebraska Public Power District	Don Schmit	Abstain	
5	New Harquahala Generating Co. LLC	Nathaniel Larson	Affirmative	
5	New York Power Authority	Gerald Mannarino	Negative	
5	Northern Indiana Public Service Co.	William O Thompson	Negative	
5	Occidental Chemical	Michelle DAntuono	Abstain	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Negative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	Glen Reeves	Negative	View
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	View

5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Arizona Public Service Co.	Justin Thompson	Negative	View
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Lisa C Rosintoski	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell		
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit		
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Abstain	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti		
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View

6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	View
6	NRG Energy, Inc.	Alan R. Johnson	Abstain	
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon	Negative	View
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Abstain	
6	Progress Energy	John T Sturgeon	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Abstain	
6	Salt River Project	Steven J Hulet	Abstain	
6	Santee Cooper	Suzanne Ritter	Negative	

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6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Benjamin Kerr	Abstain	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	View
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons		
8		James A Maenner	Negative	
8		Roger C Zaklukiewicz	Affirmative	
8		Merle Ashton		
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway	Abstain	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
9	Utah Public Service Commission	Ric Campbell	Negative	View
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	

10	Midwest Reliability Organization	James D Burley	Abstain	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Negative	View

Individual or group. (44 Responses)
Name (22 Responses)
Organization (22 Responses)
Group Name (22 Responses)
Lead Contact (22 Responses)
Question 1 (40 Responses)
Question 1 Comments (44 Responses)
Question 2 (39 Responses)
Question 2 Comments (44 Responses)
Question 3 (41 Responses)
Question 3 Comments (44 Responses)
Question 4 (30 Responses)
Question 4 Comments (44 Responses)
Question 5 (0 Responses)
Question 5 Comments (44 Responses)

Group
SERC OC Standards Review Group
Gerald Beckerle
No
While we generally agree with the changes that were made, we do not feel the standard is ready for balloting based on the following comments: R1 and R2 – In both requirements, notification of the TOP is required and appears to be for the same condition. If this is not so, the requirements need to be more specific regarding the reasons for notification. For example, R1 appears to require notification for specific conditions regarding violations of safety, equipment, regulatory or statutory requirements and R2 could be interpreted that after agreeing to and during the course of complying with a reliability directive, the entity was unable to do so. The group does not feel that these two requirements need to be separated. R3 – This requirement appears to be an operational planning requirement and may more appropriately be inserted in TOP-002-3. If it remains in this standard, we suggest the following wording: Each TOP shall inform its RC and all other TOPs that are expected to be affected by anticipated emergencies based on its operational planning analysis. (We think “assessment” is synonymous with “analysis”). We also believe that R5 is intended to cover real-time operations. The time horizons do not appear to match the requirement, i.e., Operations Planning. R4 – No comments R5 – We recommend similar language to that in R3 for consistency and clarity, i.e., R3 has “all other transmission operators” and R5 has “other Transmission Operators”. R6 – What is meant by “associated communication channels”? Data or Voice or both? Is this not covered by the COM Standards? R7 – No comments R8 – The use of Operational Planning Analysis in this requirement is not consistent with the Time Horizon of Real-time Operations. R9 – We feel the time limit should be 90 minutes for exceeding an SOL, to allow for use of TLR procedures or other measures. R10 and R11 – Logically these two requirements should be swapped so that the requirement to act is performed prior to notification of actions taken. The reference to 30 minutes should be changed to 90 minutes (see comment to R9 above).
No
R1 – No comments R2 – The word “preclude” can be interpreted as “prevent”, which would mean that any exceedance of an IROL or SOL would be a violation, regardless of duration. Other wording, such as “avoid” should be considered. R3 – No comments
Yes
R1.1 - It is our understanding that bullets should be avoided in the requirements. R2 – No comments R3 – No comments R4 – No comments
The group did not respond to this question
The SERC OC Standards review group acknowledges the work performed by SDT, and would appreciate the consideration of the groups comments listed above. “The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”

Individual
Michael Lombardi
Northeast Utilities
Yes
Suggest rearranging R4 to read: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures.
Yes
Yes
Editorial comment: Remove "M5" because there is not any corresponding text and there is not a corresponding R5.
Yes
For TOP-001-2 Requirements R3, R5, R6 and R8, suggest changing "or' to "and" - that is change "…more than x% OR less than or equal to y%..." to "…more than x% AND less than or equal to y%..."
None - thanks
Group
Northeast Power Coordinating Council
Guy Zito
No
In Requirement R2, there is a need to specify how much time should be allowed to "inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator." Suggest rewording R2 to read: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall immediately inform its Transmission Operator of its inability to perform a Reliability Directive. In Requirement R4, we suggest the following rearrangement of the sentence to improve readability: R4: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures. The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be modified to allow the TOP and RC to determine the appropriate timeframe for correcting such limits. The maintenance of Interconnection reliability and Bulk Electric System integrity is paramount, and global specifications may or may not be appropriate for a local area. Suggest modifying the appropriate wording to: within a specified time not to exceed the timeframe specified by the TOP. R9 is redundant to R11; delete R9.
Yes
No
Referring to the second bullet under R1, Part 1.1, "…Facilities at voltage levels lower than the BES;" these facilities are not enforceable under the NERC Standards. Any such references should be removed. Editorial comment: remove M5 because there is no corresponding R5.
No
Referring to the Moderate and High VLSs for TOP-001-2 Requirements R3, R5, R6 and R8, where these VLSs state "…more than x% or less than or equal to y%...", suggest changing to "“…more than x% and less than or equal to y%...". These changes would also make these VLSs consistent with the language of TOP-002-3 and TOP-003-2.
Individual
Thad Ness
American Electric Power
No

The draft of R6 states that “Each Transmission Operator, Balancing Authority, and Generator Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetry, control equipment and associated communication channels between the affected entities.” The assessment and dissemination of GOP info to the “affected entities” should be the responsibility of the local TOP and RC. It seems inappropriate to request that the GOP make these sorts of contacts, as GOPs would lack the necessary BES info to make a determination as to who should be notified.
Yes
Yes
Additional clarity is needed as to the type(s) of data that would be considered necessary for performing operational planning analysis and real time monitoring. For example, will the requirements as specified in attachment 1 for TOP-005-2 be incorporated into TOP-003-1?
Yes
AEP appreciates the work of the drafting team to make the language more concise for this standard.
Individual
Larry Grimm
Texas Reliability Entity
No
The statement “identified reliability directive” in R1 and R2, of standard TOP-001-2, would be better changed to “reliability directive.” The word “identify” requires action and the standard does not specify how the “identifying “ will be done. Furthermore, if the TOP is issuing a directive, it should be assumed that the directive is a Reliability Directive unless the TOP states that it is not. This position saves time when time is of the utmost importance. The proposed wording as presented will open the door for deliberation when corrective action should be well underway.
Yes
Yes
Yes
Group
Electric Market Policy
Connie Lowe
No
Dominion reads R1 to require an entity to ‘carry out’ the Reliability Directive. In order to comply with the requirement it must either take actions as prescribed in the Reliability Directive or it must inform the TOP that it can’t do so for one of the following: safety, equipment, regulatory or statutory requirements. It is Dominion’s expectation that an entity may know whether it has safety, equipment, regulatory, or statutory conflicts with the Directive at the time the Reliability Directive is issued, but this may not always be the case (This is especially true where the Reliability Directive is issued to personnel in a control center as opposed to being directly communicated to the operator of the Element or Facility.) Regardless, whenever an entity determines it can’t comply with the Reliability Directive, it must make notification or be non-compliant with R1. When the Reliability Directive has a time component and the entity doesn’t comply with the time required, it is non-compliant if it hasn’t completed the action(s) required unless it notified the TOP before the time component of the Reliability Directive expires (citing one of the following; safety, equipment, regulatory, or statutory requirements.) This time element guidance is not provided with this standard.
No
Dominion is unsure as to which version (clean or redline) of the language in the grey box (for R1) the SDT intended. The sentence (in red line version) appears to read “Rationale for Requirement R1:

Operational Planning Analysis (OPA) does not the analysis even if those tools are not available." Please clarify. We also did not find any changes to the Data Retention (red line version).
No
Is this question meant to refer to TOP-003-2? If so, then Dominion's response is that we agree, but do not see why the SDT felt it necessary to add "web postings with acknowledgement" to M2 and M3. The sentence "Such evidence could include but is not limited to ...." was sufficient without the addition. Dominion believes this language will invite others to want to add the types of evidence found usefher may grow over time.
Group
Western Electricity Coordinating Council
Steve Rueckert
Yes
Yes
Yes
No
These same comments were submitted with our vote on the non-binding VRF and VSL poll WECC agrees with the VRFs and the majority of the VSLs. However, we beleive consideration of the following will improve the VSLs. TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs to not appear to address the situation where the responsible entity did not include three or more of the required elements of the documented specification for the data necessary for it to perform its required Operations Planning Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?
No additional comments
Group
BC Hydro
Patricia Robertson
Yes
Yes
No
R1.1 refers to "Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES". In the previous Consideration of Comments, it was noted that "Facilities below 100kV may have material impact to the BES and, as such, are within the scope of the requirement ...". BC Hydro feels that the wording in R1.1 "Facilities at voltage levels lower than the BES" is open-ended and it does not clearly reflect that these extra Facilities have been deemed as having material impact to the BES and therefore are subject to the NERC MRS.

Group
Progress Energy
Jim Eckelkamp
No
No
TOP-002-3 R2...Our initial concern was that an auditor could read this requirement as requiring a specific plan to address each IROL and SOL. This interpretation does not make much sense, but it is supported by the wording of the measure, which says, “Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL and each SOL.” We can picture an auditor going down a complete list of IROLs and SOLs and asking, where is your plan for A, where is your plan for B, etc. The standard should not require the Transmission Operator to prepare a plan to address IROLs and SOLs unless the Operational Planning Analysis indicates the potential for a thermal or voltage problem for that element due to normal (N-0), contingency (N-1), or sensitivity analysis result. So, the logical way to read this requirement is to say that the completion of the Operational Planning Analysis is the “plan”, and if there are no IROL/SOL limits exceeded, then you have met the requirement. If this is what the SDT meant, then the wording of the requirement should be revised and clarified. Also, We are concerned about the requirement to “…plan to preclude operating in excess…”, because “preclude” is defined to mean “make impossible” or “take action in advance to make impossible”. Precluding these events is inconsistent with the time limits established in the new TOP-001-3 standard. This could be read to require pre-contingency action for any contingency involving an IROL/SOL, which could cause major operational problems to say the least. All of the prior standards, including the TOP, TPL, and the Rules of Procedure governing the seasonal assessment process provide latitude in how studies are performed, and what pre- and post- contingency actions are taken. This standard should be clarified to provide comparable latitude in addressing IROL and SOL issues. Just changing “preclude” to “mitigate” would be a good start…. Also, requirement R2 is unacceptably vague in that it requires plans for SOLs that “support internal area reliability” without indicating how those SOLs are identified or selected as a subset of all SOLs. Also, R8 of TOP-001-3 requires that the RC be notified of the existence of these SOLs, whatever they are….
No
We perform many studies in different time frames that could be viewed as an “Operational Planning Analysis”, from seasonal assessments, to OPC studies, to outage planning studies, day-ahead planning studies, real-time CA studies, etc. Our question is, which of these studies will be subject to all of the requirements in TOP1,2,3, and particularly to the data specification requirements in TOP-003? Will Transmission Operators be expected to meet these requirements for ALL studies, or can we designate one specific study process as the “Operational Planning Analysis” study (and, by implication, exempt others from the requirements). Also, TOP-003, R1 also includes “real-time monitoring” in the scope of the requirement for the data specification, so does this include the EMS and all of its data? This would require multiple data specifications, because the EMS and off-line PSS/E models we use to perform various studies would require different data specifications, have different contacts that provide information, etc.
Group
Public Service Enterprise Group LLC
Mikhail Falkovich
No
The PSEG Companies interprets “long term outages” to be planned season outages not emergent issues that result in a long duration outage of a BES facility.

Group
Wisconsin Electric Power Company
Jim Keller
No
R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator, these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase “negatively impacted interconnected NERC registered entities” is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA’s of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse Reliability Impact on another’s area, hence an emergency there is somewhat circular.
No
R3 the TOP should provide the plan to its RC and BA (s) in addition to notifying other entities of expected actions. The use of the phrase “all registered entities” is too open ended, and not limited to operational functions as it should be. In addition some actions may be required of entities not registered.
No
R2 & R3 should not use the term monitored, the TOP or BA should distribute its data specification to all entities that are included in that specification to enable the proper Operational Planning Analyses and Real-time monitoring. R4 should not include both asset owners and operators, example generator xyz net output at the transmission interface needs to be the responsibility of one and only one entity to provide. Very confusing if both the GO and GOP have the same responsibility.
Group
NIPSCO
Joe O'Brien
The new standard appears to treat SOLs and IROLs in a similar manner, which should not be the case. Also, in TOP-003-2 R1 1.1 the second bullet may incorrectly bring non-BES distribution facilities into play.
Individual
Joe Petaski
Manitoba Hydro
Yes
The term ‘reliability entity’ used in TOP-001-02 should be changed to ‘registered entity’.
Yes
Yes
Yes
Group

Luminant Power
Mike Laney
Yes
Yes
No
While we agree with the concept of the TOP and BA creating a specification for data necessary for Operational Planning and Real-time monitoring, we feel that Requirement 1.2 should explicitly state that the format should be mutually agreeable to the TOP and BA and the parties receiving the data request under R2 and R3. Additionally, for R1.3, we feel the same mutually agreeable requirement between the TOP and BA and the parties receiving the data request should apply be added for the periodicity requirement.
Yes
Individual
Jim Howard
Lakeland Electric
No
TOP-001-2 Coordination of Transmission Operations R5 seems to limit communications / coordination more than the version 1 standard (old R7) to only those actions that can result in an Adverse Reliability Impact, which are very few. This is probably underperforming and FERC will probably not like it. Some other limits to the scope of communications, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations of Bulk Electric System Facilities known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load." I disagree with deleting TOP-008-1 R3 that allows TOPs, after exhausting other methods to alleviate the problem, to open a Facility if it is imminent danger of catastrophic failure. The requirement should be revised and included in TOP-001-2 as something like the TOP shall request permission of the RC to disconnect the Facility if there is a threat of imminent catastrophic failure, the RC can direct otherwise "unless the direction per Requirement (IRO-001-2) R2 can not be implemented or such actions would violate safety, equipment, regulatory or statutory requirements" (IRO-001-2, R3). Exceeding an IROL that might result in a system restoration event with equipment capable of being restored is preferable to waiting for a Facility to be disconnected due to catastrophic failure, still exceeding the IROL due to that disconnection, but resulting in a system restoration exercise with catastrophically failed equipment. An example of this is the 1977 blackout of NYC which was exacerbated by catastrophically failed equipment. On R7 and R9, I'm concerned about the "for how many contingencies" question, e.g., are we held to the same criteria for "extreme contingencies"? The BAL standards have exclusions for multiple contingencies in meeting the performance requirements (e.g.,BAL-002-0 D1.4). There is not such consideration for "Extreme" contingencies in R7 and R9. If a bad event occurs beyond the criteria we operate the system to, are we setting ourselves up for failure and fines?
No
TOP-002-3: Operations Planning The prior version 2 standard was applicable to both the BA and the TOP. The new standard is just the TOP, which is appropriate; however, it was the old TOP-002-1 that basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed (at least that's how I interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). Since BAs are eliminated from the new version 2 standard, and since there is no similar requirement in the BAL standards that I am aware of, FERC will likely see a reliability gap that no entity is ensuring that enough generation is being committed to serve current day / next day peak loads, e.g., no entity seems to be responsible for validating unit commitment. The SDT claims that BAL-001-1 covers the operations planning perspective of a BA, but, BAL-001-1 covers unit commitment only loosely on an annual or monthly basis. The new version also doesn't talk about the

time frame of operations planning. The old version clearly had current day, next day and seasonal operations planning requirements that probably ought to be retained, as opposed to the ambiguous phrasing of R1.
No
TOP-003-3: R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced, and will probably be perceived by FERC as being too flexible a requirement that would allow a TOP or BA to do less than they are currently required. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards to at least prove to FERC that we are not subtracting data/information requirements. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower then the BES" there are two problems with the statement: 1. Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ....". The second use of Facilities in the phrase ought to be deleted (see below), or at minimum, replaced with the term Elements. 2. Although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 "mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. Suggest clarifying who is mutually agreeing. Also, from a reliability related perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14. R1.3 and R1.4 - should have the same characterization of R1.2, e.g., "mutually" or stakeholder process driven to establish a schedule.
Yes
Individual
Greg Rowland
Duke Energy
No
• We disagree with the revised definition of Reliability Directive. The phrase “or expected” creates compliance uncertainty and should be struck. • R8 - We have made this comment before and continue to strongly believe that the phrase “supporting its internal area reliability” should be replaced with the phrase “having an Adverse Reliability Impact”. In the Consideration of Comments the drafting team acknowledges that the intent of the requirement is to allow a TOP to go beyond what is needed to support BES reliability, and address local load concerns. We believe such a requirement has no place in a mandatory reliability standard, because an entity can always do more than what is required. The inclusion of the concept of “supporting internal area reliability”, creates compliance risk which we believe is unnecessary and is not supported by Section 215 of the Federal Power Act. Auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”, a nebulous and undefined term. Consistent with our argument on this requirement, we also question how the drafting team was able to justify a “Medium” VRF. It very clearly doesn’t meet the guidelines. • R9 – The VRF has been changed from “High” to “Medium”. Consistent with our previous comment on R8, we question how the drafting team was able to justify a “High” or “Medium” VRF. It very clearly doesn’t meet the guidelines. • R11 – Including the SOLs identified in R8 in this requirement effectively makes those SOLs equivalent to an IROL for mitigation purposes. Consistent with our comments above on R8 and R9, our concern is that under this approach all equipment ratings could potentially become SOLs subject to the same mitigation as IROLs.
No
• This standard uses the capitalized term “Operational Planning Analysis” which is not currently a NERC defined term. How is this to be applied in the standard? • R2 – We reiterate our comments on TOP-001-2 regarding the problematic phrase “supporting its internal area reliability”. Will an entity’s Operational Planning Analysis be found deficient if no SOLs have been identified which support “internal area reliability”? We believe that it is certainly possible. Furthermore, in M2, what evidence will be required to be presented to demonstrate that an entity has no SOLs which “support internal

area reliability”? • R3 – insert the word “NERC” before the word “registered” to add clarity.
No
The second bullet under R1.1 has been changed so that now operating parameters for all facilities at voltages lower that BES are required. The phrase “at the discretion of the Transmission Operator or Balancing Authority” must be restored in this requirement.
No
Consistent with our comments about the unacceptable phrase “supporting local area reliability” we do not support the VRFs and VSLs.
Individual
Rex Roehl
Indeck Energy Services
Yes
Yes
No
TOP-001-2 R6: The VSL's do not consider the case of a small GOP (and possibly DP or LSE) which only affects the TOP or BA. The VSL needs to reflect the significance of the planned outages. Planned outages of wind projects is of lower reliability significance than of large base load plants or black start units. The SDT needs to define the differences. Planned outages on GOP facilities that exceed the NERC Reportable Disturbance threshold for the BA would be Severe. Those between 75% & 100% of Reportable Disturbance would be High. Those between 50% and 75% of Reportable Disturbance would be Medium and all others would be Lower. TOP-003-2 R4: Only having Severe VSL avoids the difficult process of deciding what data is important. Data on outages of wind projects is of lower reliability significance than of large base load plants or black start units. The SDT needs to define the differences. Data on facilities that exceed the NERC Reportable Disturbance threshold for the BA would be Severe. Those between 75% & 100% of Reportable Disturbance would be High. Those between 50% and 75% of Reportable Disturbance would be Medium and all others would be Lower.
Individual
Darryl Curtis
Oncor Electric Delivery
No
For R6- Oncor does not believe that the proposed language will provide a coordinated communication effort in the event of a planned outages of telemetry, control equipment and associated communication channels. In addition, the term “negatively impacted interconnected registered entities” is too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity.
Yes
Yes
Yes
Individual
Don Schmit
Nebraska Public Power District

No
NPPD does agree in general with the intent of the proposals under this ballot, however there is change needed in TOP-002-3. The language in TOP-002-3 R2 is not clear and could be interpreted to require an entity to include all IROL's in the interconnection, which is way too broad. NPPD suggests that R2 of TOP-002-3 be reworded to be clear that the requirement is addressing IROL's and SOL's "within the Transmission Operator's Area".
Individual
David Thorne
Pepco Holdings Inc
Yes
Should the standard be applicable to a TO? Specially it would appear that R1 and R2 should be applicable to a TO in addition to the other listed entities.
Yes
No
In R1.1 has an open ended requirement for operating parameters for non BES facilities. Should the language limit that to only those facilities that have an impact on BES facilities? If so, should long term outages of those facilities also be required?
Yes
Individual
Kirit Shah
Ameren
No
(1)We do not agree with the definition of “Reliability Directive”. The phrase “expected” Emergency creates uncertainty and will create controversy. We suggest to remove the “actual or expected” phrase, and instead add “… condition or situation that threatens the reliability of the Bulk Electric System and is likely to lead to cascading, separation, islanding, ….” after emergency consistent with the intent of the FPA and NERC Standards. (2) In R2, the SDT uses the adjective "identified" which, in the Compliance and Enforcement arena, unfortunately may imply a new and different type of Directive (an "identified Reliability Directive"). We assume the SDT meant to imply with the word "identified", that the TOP would let know the receiving party explicitly that the communication that they were receiving was in fact a Reliability Directive and not just some other form of operating communication. IF that is the case, we suggest that the SDT simply state that fact as follows, "A Directive issued by a TOP which is referred to in the ensuing 3-way communication with the recipient of that Directive using the specific words Reliability Directive". (3)In R6, we have concerns with the Generator Operator having to “notify negatively impacted interconnected NERC registered entities of planned outages of telemetry…” etc. This is too broad for a GOP to be lumped in with the TOP and BA, since most GOPs do not have the knowledge if these planned outages would negatively affect other NERC entities. We believe that R6 should apply to TOP and BA, and maybe have R6.1 that requires the GOP to notify their specific TOP and BA of planned outages of telemetry, control equipment, and communication channels which in turn would generate communication from the host TOP and BA to others so affected. (4) In R8, what is meant by “internal” area reliability? We have a significant concern form a compliance perspective about how would it be interpreted and audited. (5) R11 refers to R8 and SOL. Is it the intent of the SDT to consider SOL effectively the same as IROL for purpose of this requirement?
No
(1)R1 refers to “Operational Planning Analysis” which is not a defined term. Similarly, R3 uses the

phrase “registered entities identified in the plan(s) cited in R2 which is confusing. Please define/clarify these terms or phrases. (2) In R2 (similar to R8 in TOP-001-2) , what is meant by “internal” area reliability? We have a significant concern form a compliance perspective about how would it be interpreted and audited.
No
In R1, 1.1 “at the discretion of the Transmission Operator or Balancing Authority” phrase should be reinstated.
No
As stated in comments above, we have concerns about the newly introduced term “internal” area reliability in TOP-001 and TOP-002 and proposed Medium VRF to the corresponding requirements.
Group
Bonneville Power Administration
Denise Koehn
Yes
Yes
Yes
No
TOP-003-2: The proposed sanctions seem disproportionate to the offense. If a BA fails to contact an entity that influences its operation, the failure does not seem to affect anything except the evaluation’s accuracy to the offending BA. Furthermore, it seems unlikely that a deliberate omission would be made since it’s in a BA’s best interest to have accurate assessments. TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs to not appear to address the situation where the responsible entity did not include three or more of the required elements of the documented specification for the data necessary for it to perform its required Operations Planning Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?
Group
Imperial Irrigation District
Jesus Sammy Alcaraz
Yes
R5 - should include notification of the Reliability Coordinator involving Adverse Reliability Impact M1 (b) - did not comply with the indentified directive and informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. M5 – include the notification to the Reliability Coordinator known or expected to result in an Adverse Reliability Impact Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5
Yes
Yes
Suggestions/Comments:Could R2 & R3 be included as sub bullets of R1 (R1.1 & R1.2)? R1 - Each Transmission Operator and Balancing Authority shall have create and maintain a formal documented

plan/procedure for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. R2 - Each Transmission Operator shall distribute its formal data plan/procedure specification to the Reliability Coordinator and entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator. R3 - Each Balancing Authority shall distribute its formal data plan/procedure specification to the Reliability Coordinator and to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.
No
IID staff and SME are supporting WECC postion and providing those comments below. TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs to not appear to address the situation where the responsible entity did not include three or more of the required elements of the documented specification for the data necessary for it to perform its required Operations Planning Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?
1. The proposed versions of the standards appear to remove the redundancy and provide better clarity to the requirements. However the period when the proposed standard becomes effective is cumbersome. PROPOSED - Suggest two effective dates be provided? For example: Regulatory approval 05/01/2011 Effective Date 10/01/2013 Effective Date “Not Requiring Regulatory Approval” 10/01/2013 CURRENT - Effective Date: All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption. 2. Recommend that the RSAWS for these proposed standards be revised and posted when the standard versions become effective. 3. Data Retention – Could the Data Retention be displayed in a matrix format (see example below) EXAMPLE Function Requirement Evidence Retention Period TOP R1 Compliance with RC Directives Current Year + Previous Year BA R2 Compliance with TOP Directive Current Year + 1 Year GOP R3 Compliance with TOP Directive Current Year + 1
Individual
Anthony Jablonski
ReliabilityFirst
Yes
Yes
Yes
No
ReliabilityFirst generally agrees with the Violation Risk Factors (VRFs) but disagrees with the Violation Severity Levels (VSLs) for the following reasons: TOP-001-2 VSLs 1. VSL for R2 a. The word “comply” is not within the language of R2 and should be removed from the VSL. R2 simply requires the Applicable Entities to “… inform its Transmission Operator…”. This is a violation of the FERC Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement” 2. VSL for R8 a. The term “local area reliability” should be replaced with “internal area reliability” to be consistent with the language in R8. This is a violation of the FERC Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement” TOP-003-2 1. VSL for R1 a. The sub-parts should be referenced in the VSL. (i.e. “The responsible entity did not include one of the required elements, per Requirement R1, Parts 1.1 though Parts 1.4, of the documented specification…”) b. There is no provision if an Applicable Entity fails to include three or more of the

required elements. VSLs should be gradated to include failure of including both three and four sub parts.
Individual
Denise Lietz
Puget Sound Energy
Yes
Yes
Yes
The second bullet in R1.1 needs clarification. As originally drafted, this was permissive language allowing entities to include non-BES information in their data specifications. However, with the revisions, this section now requires all entities to do so, whether or not such data is necessary or pertinent for their operations. As a result, the second bullet should be revised to retain its permissive character or should be removed from the standard altogether.
No
In TOP-001-2, R8, the time horizon should include Operations Planning and Same-day Operations, in addition to the currently-listed Real-Time Operations. In TOP-002-3, R3, the VRF is listed as “High”. However, according to the document “Violation Risk Factor and Violation Severity Level Assignments”, the appropriate level is “Medium”, which is also more consistent with the assignments associated with other requirements throughout these proposed standards. In TOP-002-3, the VSL matrix entries associated with R3 need to have additional references to “reliability entities” changed to “registered entities”.
Group
Southern Company
Antonio Grayson
No
It would be preferable to use the term “reliability entities” or at least replace the generic term “registered entities” with a listing of the Functional Model Entities that need to be notified. The use of registered entities would require reliability information to be given to marketing entities. R2 and M2 are confusing due to a mismatch in using “issued” and “identified”. R2 lists the directive as “identified”, while M2 lists it as “issued, identified, “. It is suggested that the following phrasing be used: “an issued Reliability Directive” or “an identified Reliability Directive”. Please consider merging R1 and R2 into a single requirement that requires entities to comply with directives or provide a reason to the TOP as to why it’s unable to do so. Then, the measure could be that an entity either complied with the requirement or informed the TOP of its inability to comply. I think R2 implies that there may be reasons other than safety, equipment, regulatory, or statutory restrictions that may prevent a Generator Operator from performing an identified Reliability Directive as it refers to the GOP’s “inability” to perform the action and doesn’t specifically reference these restrictions again. I agree with your comment that the best way to handle this would be to combine R1 and R2 into a single Requirement perhaps with the following wording: “R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity is unable to perform the actions required by the Reliability Directive (due to violation of safety, equipment, regulatory, or statutory requirements or other reasons) and informs its Transmission Operator upon recognition of its inability to perform the actions. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]” For R2, The question came up for what was more appropriate – issued or identified, and requested Reliability Directive was also suggested as an option. If the reason for this descriptive term is to clarify that the Transmission Operator has declared “this is a Reliability Directive”, then identified would be the more appropriate descriptive term and should be used in a consistent manner. For R6, we take issue with changing the wording from “telemetering equipment” to telemetry as the former is equipment and the latter implies data. The distinction is that

under the current wording, the entity is required to coordinate the outage of the piece of equipment that telemeters data (i.e. the RTU) whereas the proposed change implies that the entity will have to coordinate any outages of telemetered data. This could have significant implications as there may be 1000+ data points being telemetered by an RTU, and each data point may come from a unique piece of equipment in the plant. Is the intent that removal of, say, a pressure transmitter or a MW transducer from service for routine calibration requires notification to the Reliability Coordinator? For R6, Fleet Operations functioning as Generator Operator does not directly notify the RC, but interfaces instead with the PCC. Forwarding rules in GENcomm will deliver notifications to the RC. This impacts the evidence for M6, if the expectation is a direct communication. For R6, The use of a comma after “control equipment” in the list in R6 would make it easier to understand this requirement. (suggestion: make it match to M6). For R9, this is a duplicate requirement and does not add to reliability. This requirement is addressed in TOP-004-2 R1. For R10 and R11, these are duplicate requirements and do not add to reliability. These requirements are addressed in TOP-007-0.
No
R1 -It is still unclear to us if Operations Planning Analysis includes Contingency analysis as the NERC Glossary does not explicitly state. Edits to the rationale box were such that we could not understand the intent. R3-Is the standard expecting a comprehensive written plan as a result of the planning that takes place in R2? Is the intent of this requirement to notify all registered entities that may be affected by a mitigation plan for the next day? Example: An SOL is identified in the Operational Analysis for the next day from R2. The plan to mitigate this SOL is to call an IDC-TLR. The level of the TLR may or may not reach level 5. If the TLR reaches level 5 many generators will be required to be re-dispatched inside and outside of the TOPs area. This requirement will require the transmission operator to notify every Generator Operator that could possibly be re-dispatched for a TLR-5. It would be preferable to use the term “reliability entities” or at least replace the generic term “registered entities” with a listing of the Functional Model Entities that need to be notified. The use of registered entities would require reliability information to be given to marketing entities.
Yes
Yes
(Please note that these comments relate to TOP-001-2). It is suggested that the R1 VSL Severity text be written as an either/or statement. “entity either did not comply with (a directive) or did not inform ….” R1, as its currently written, gives an entity these two choices. The R2 VSL Severe test is more expansive than Requirement 2. To match R2, it is suggested that the test read” …entity did not inform the TOP of its inability to comply” The R6 graduated VSLs, as written, are hard to understand. For a given outage, it is unclear how many “affected entities” there are likely to be. Also for R6, the OR statement has conflicting scope (i.e. planned outage of telemetry OR with planned outage of telemetering equipment).
Individual
Jennifer Eckels
Colorado Springs Utilities
No
Colorado Springs Utilities appreciates the opportunity to comment on this draft and the changes made to this standard. The following comments are specific to requirements R3,R4, R8/R10,R9, & R11. R3. By changing "of" to "by" there is now no object to the verb "inform". Suggested language: "Each Transmission Operator shall share its assessment of its Operational Planning Analysis with its Reliability Coordinator, and all other Transmission Operators that are known or expected to be affected, based on that assessment, by actual and anticipated Emergencies." R4. Colorado Springs Utilities agrees with those who have commented on previous drafts that the language strongly implies that the TOP rendering assistance is obligated to ensure the entity receiving assistance has implemented "comparable emergency procedures." We recommend the requirement be rewritten: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Transmission Operator requested to provide such assistance may require that the requesting entity first implement its own comparable emergency procedures.” R8/R10. SOLs, which are not IROLs, by definition, do not impact interconnection reliability and should be the responsibility

of the TOP, not the RC, and therefore should not require being reported to nor monitored by the RC. R9. Does R9, as written, prevent the TOP from employing the option to permit equipment life reduction to avoid load shed? R11. Despite the SDT's clarifying comments provided during previous comment periods, this requirement continues to appear duplicative to R7 & R9 and seems to provide opportunity for double jeopardy in the event of non-compliance with one of those requirements. We suggest R11 be eliminated. If exceeding the SOL or IROL is remedied and restored within the required time frame, then the operator or the system has taken appropriate mitigating action.
Yes
Colorado Springs Utilities respects the difficulty in crafting language which satisfies all potential interpretations of a requirement. We do, however, suggest changing "planning to preclude operating" under R2 to "plan to operate", giving you the following: “Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator via the Operational Planning Analysis performed in Requirement R1 as supporting its internal area reliability.” Perhaps the definition of SOL should be revised to include the principle of "internal area reliability". Then, everything not IROL or SOL could go back to being facility ratings or the like.
Yes
Colorado Springs Utilities believes the question should be directed toward TOP-003-2.
No
TOP-001-2 R8 & R9 VRFs should be "Low" TOP-002-3; R2 - IROLs should be "High" / SOLs should be "Low". R3 should be "Medium".
Individual
Russell A. Noble
Cowlitz County PUD
No
Cowlitz respectfully disagrees with the SDT concerning requirements R1 and R2 addressing priori prohibitions and post-agreement to comply with an identified Reliability Directive. Cowlitz can see no Reliability difference between an immediate “priori” and post-agreement identification of a TOP Reliability Directive action that would violate safety, equipment, regulatory, or statutory requirements. In each case the outcome is the same: the action is not complied with due to an inability to perform, and the TOP is informed “upon recognition.” Therefore R1 and R2 are effectively duplicitous in this regard. Cowlitz suggests that the verbiage “…the respective entity informs its Transmission Operator that…” be removed from requirement R1. Cowlitz agrees with the SDT concerning “Reliability Directive” is not meant to equate to the urgency of a situation. This standard establishes the authority of the TOP to issue directives, and clear communication of such authority has been requested by this commenter in the past. Cowlitz applauds the SDT's stand on this issue. On all other matters, Cowlitz either agrees or abstains with the SDT.
Yes
As long as System Operating Limits (SOLs) are tied specifically to Bulk Electric System facilities by other standards, Cowlitz approves of all the changes.
No
Cowlitz has no disagreement with any of the changes made; however Cowlitz struggles why the Load-Serving Entities (LSEs) are included in the Applicability section. From requirements R2 and R3 it is clear that Facility monitoring and status is involved. From the Reliability Functional Model it is clear that LSEs do not own Facilities, but rather are more ambassadors between the End-use Customers and registered entities that do own facilities. Although the Statement of Compliance Registry Criteria implies that the LSEs might own UVLS and/or UFLS equipment, the Reliability Functional Model is clear that the LSE only helps identify those critical customer loads that should be excluded in such load shedding programs. Therefore, Cowlitz urges the SDT to remove the LSEs from the Applicability section. Cowlitz also suggests that Distribution Providers be included in the Applicability section as these entities do own Facilities that may require monitoring and status by the TOP and BA.
Yes

Individual
Jason Snodgrass
Georgia Transmission Corporation
Yes
Yes
No
Section 215 of the FPA provides that the ERO “shall have authority to develop and enforce compliance with reliability standards for only the BPS.” In Order 743A, the commission acknowledged that “Congress has specifically exempted ‘facilities used in the local distribution of electric energy” from the BPS definition. R1.1 for TOP-003-2 references distribution assets which are outside the scope of NERC standards. GTC recommends removing reference to “Facilities at voltage levels lower than the BES”
Individual
Bill Keagle
BGE
Yes
Comment on proposed TOP-001-2 Reliability Directive definition: Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency. This needs to also include: The RC, TOP or BA must clearly state that “This is a Reliability Directive”.
No comment.
No comment.
No comment.
No comment.
Individual
David Kiguel
Hydro One Networks Inc.
No
In Requirement R2, there is a need to specify how much time should be allowed to “inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator.” Suggest rewording R2 to read: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall immediately inform its Transmission Operator of its inability to perform a Reliability Directive. In Requirement R4, we suggest the following rearrangement of the sentence to improve readability: R4: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, contractual or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures. The requirements (R9, 10 and 11) that stipulate returning SOLs which “have been identified as supporting internal area reliability” within 30 minutes should be modified to allow the TOP and RC to determine the appropriate timeframe for correcting such limits. The maintenance of Interconnection reliability and Bulk Electric System integrity is paramount, and global specifications may or may not be appropriate for a local area. Suggest modifying the appropriate wording to: within a specified time not to exceed the timeframe specified by the TOP. R9 is redundant to R11; we suggest deleting R9.
Yes
No

Referring to the second bullet under R1, Part 1.1, "…Facilities at voltage levels lower than the BES;" these facilities are not enforceable under the NERC Standards. Any such references should be removed. Editorial comment: remove M5 because there is no corresponding R5.
No
Referring to the Moderate and High VSLs for TOP-001-2 Requirements R3, R5, R6 and R8, where these VSLs state "…more than x% or less than or equal to y%…"; we suggest changing to "…more than x% and less than or equal to y%…". These changes would also make these VSLs consistent with the language of TOP-002-3 and TOP-003-2.
Group
FirstEnergy
Sam Ciccone
No
We have the following comments and suggestions: 1. R3 – Since this requirement is describing actions to be taken in Real-time as shown in the Time Horizon, the use of the term "Operational Planning Analysis" may not be appropriate. This is because an analysis in the operations planning timeframe is restricted to next day and up to 12 months in the future. We suggest that the team reconsider of the use of this phrase and remove the last part of this requirement, specifically remove "based on its assessment of its Operational Planning Analysis". 2. R6 – We do not agree with the phrase "and negatively impacted interconnected NERC registered entities". We believe that it should be the responsibility of the Reliability Coordinator to notify all impacted entities since they are afforded the wide-area view of the area. 3. R6 – The phrase "control equipment" is too broad and lacking clarity with regard to the phrase "between the affected entities". We suggest that additional clarification be added by providing examples of the types of control equipment or the loss of functionality that could occur due to the outage.
Yes
We support the requirements but have alternate wording suggestions for R2 as follows: "R2. Each Transmission Operator shall not operate in excess of each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1."
No
R1 – Subpart 1.1, Bullet #2 – We suggest that the team strike the phrase "and Facilities at voltage levels lower than the BES". NERC reliability standards are meant to provide an adequate level of reliability to the Bulk Electric System, and therefore non-BES requirements are beyond the scope of the standards. Furthermore, the current NERC initiative to revise the definition of BES and provide specifics around what is both included and excluded will alleviate any potential gaps in reliability of the BES.
No
We cannot support the current VSL until our suggested changes to the requirements are made.
Group
City of Tacoma or Tacoma Public Utilities
Chang Choi
Yes
1. The Standard Development Roadmap, page 2, states there are no new or revised definitions yet there is a revised definition for "Reliability Directive." Reliability Directive is not listed in NERC's Glossary of Terms. 2. The terms "Operational Planning", "Same Day Operations" and Real-time Operations" need definitions that include a time horizon. 3. R1: The language is redundant with R2. Removing "…the respective entity informs its Transmission Operator that…" from R1 would eliminate the redundancy. 4. R5: New R5 language replaces the old language from TOP-001-2 R 7.3. Proposed: "Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or

equipment failures and changes in generation, transmission or load." Existing R7, R.3: "When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generation Operator shall notify the Transmission Operator and the Transmission Operator shall notify its Reliability Coordinator and adjacent Balancing Authority, at the earliest possible time." Suggestion – Include language to identify the time requirement for communications including after-the-fact notifications. The purpose of the requirement is to inform, yet there is no associated timeframe. 1. R10: Similar to R5, this requirement also needs an associated timeframe to inform the RC, otherwise it's difficult to measure.
No
• R2: "Each Transmission Operator shall plan to preclude operating in excess of Interconnected reliability Limits (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified as supporting its internal area reliability, as a result of the Operational Planning Analysis performed in Requirement R1." Suggestion - The statement in red is a double negative and difficult to follow. Rewrite this sentence to be a positive statement to avoid confusion, for example, "Each Transmission operator shall plan to operate within identified …"
No
1. In general, the standard language as written is vague. 2. R1: Though a minimum list of required data may be construed as too prescriptive and may "stifle creativity and innovations," the absence of a pre-defined list will promote inconsistencies between entities and may risk an Auditor interpreting what data is needed for an "Operational Planning Analysis" differently from the utility. 3. R1.1: The term "long term outages" needs a definition. How long is "long term?" 4. R1.1: The term "operating parameters"also need a definition.
No
1. TOP-001-2: In general, when "failure to inform" results in VSL, the timeframe for informing needs to be defined. 2. TOP-002-3, R3: The VSL language for all levels is confusing. At the minimum, the percentages for should be consistent between Lower, Moderate, High and Severe. 3. TOP-003-2: Similar to TOP-002-3, the VSL language for all levels is confusing and should be consistent between VSL levels.
Comments: Please provide the definitions for new terms in the first version of the Standards. Once they have been introduced and/or the standard is undergoing a new revision – they could be removed to the Glossary for future reference.
Group
MRO's NERC Standards Review Forum
Carol Gerou
No
We disagree with the statement in R8 ". . . have been identified by the Transmission Operator as supporting its internal area reliability . . .". This statement puts an SOL on the same level as an IROL, which is not the intent of an SOL. The Transmission Operator should inform the Reliability Coordinator of IROL's that may impact the reliability of the BES, but not SOL's. R9 - We continue to believe that SOL's should not be a part of the TOP-001-2 standard. There are not identified timeframes in the NERC standards that apply to SOL's. There has been no basis for the 30 minute timeframe listed, as "generally accepted by the industry" is not a technical basis, and SOL's are often tied to thermal limits and other steps can be taken locally to offset the SOL. If SOL's must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded. An example definition might be "non-thermal SOL's are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability." Including SOL's in R11 effectively makes them equivalent to IROL's for mitigation purposes. Consistent with our comments in R8 and R9, SOL's must either be removed from consideration, or more narrowly defined to the appropriate set of SOL's that directly impact the reliability of the BES (cause instability, uncontrolled separation, or cascading outages). The SDT should ensure that TOP-001 consistent with FAC-014-2 R2 concerning identification of SOLs.
No
believes that the boundaries are not identified in TOP-002-3 R2. For IROLs, the boundaries should be limited to the Registered Entities footprint.

No
As currently written, R1.1 could be interpreted to include all of the distribution facilities of a Registered Entity. It needs to be revised to include only the lower voltage facilities proven to impact the reliability of the BES. In R1.1, please clarify “long-term” as the term applies to outage of BES Facilities. What length of time must pass before an outage I is considered “long-term”? In R1.1, clarify “Operating Parameters” as the term applies to BES Facilities and those Facilities at voltages lower than the BES. We recommend that a list of required parameters be included within the Requirement. Recommend rewording R2 (and R3) as follows: “Each Transmission Operator shall distribute its data specification document to all NERC Registered Entities that provide Facility status to the Transmission Operator.”
Group
LG&E and KU Energy
Brent Ingebrigtson
No
While LG&E and KU Energy generally agrees with the changes that were made, we do not feel the standard is ready for balloting based on the following comments: R1 and R2 – In both requirements, notification of the TOP is required and appears to be for the same condition. If this is not so, the requirements need to be more specific regarding the reasons for notification. For example, R1 appears to require notification for specific conditions regarding violations of safety, equipment, regulatory or statutory requirements and R2 could be interpreted that after agreeing to and during the course of complying with a reliability directive, the entity was unable to do so. LG&E and KU Energy does not believe that these two requirements need to be separated. Moreover, to the extent there are duplicative requirements for the same issue, if a violation were to occur, an entity may be in violation of two requirements instead of one. The standards must clearly state what is required and must do so without creating duplicative or overlapping requirements or sub-requirements. As presently drafted, R1 and R2 create confusion as to what is required and could result in multiple self reports for the same potential violation and potentially additional penalties as a result of two violations for what appears to be the same issue. R3 – This requirement appears to be an operational planning requirement and may more appropriately be inserted in TOP-002-3. If it remains in this standard, we suggest the following wording: Each TOP shall inform its RC and all other TOPs that are expected to be affected by anticipated emergencies based on its operational planning analysis. LG&E and KU Energy thinks “assessment” is synonymous with “analysis”). We also believe that R5 is intended to cover real-time operations. The time horizons do not appear to match the requirement, i.e., Operations Planning. R4 – No comments R5 – LG&E and KU Energy recommend similar language to that in R3 for consistency and clarity, i.e., R3 has “all other transmission operators” and R5 has “other Transmission Operators”. The requirement is unclear in describing who is responsible for informing whom, needs to be rewritten to clarify. R6 – What is meant by “associated communication channels”? Data or Voice or both? Is this not covered by the COM Standards? Additionally, please clarify what is intended by terms “negatively impacted interconnected NERC entities” and “control equipment” as used in proposed R6. R7 – No comments R8 – The use of Operational Planning Analysis in this requirement is not consistent with the Time Horizon of Real-time Operations. Based on the NERC definition Operational Planning Analysis is considered future looking (next-day through 12 months) this would exclude modification to SOLs made during Real-time Operations. SOLs utilized in Operational Planning Analysis are based on certain assumptions given forecasted conditions or historical data. Real-time operating conditions can vary drastically from these assumptions and there needs to be flexibility in modifying SOLs to account for these actual system conditions. R9 – The 30 minute duration is quite restrictive in resolving an SOL exceedance, especially for those that are considered to support internal area reliability. Does this apply only to actual SOL exceedances, or does it also include post-contingent SOL exceedances? LG&E and KU Energy feel the time limit should be at least 90 minutes for exceeding an SOL (especially for post-contingent SOLs), to allow for use of TLR procedures or other measures which often take more than 30 minutes to implement. There needs to be some flexibility in establishing Real-time Operations SOLs based on actual system conditions separate from the Operational Planning Analysis. R10 – Because the Time Horizon is “Real-time Operations” the SOLs communicated to the RC per this requirement should be the Real-time

Operations established SOLs, not the Operational Planning Analysis SOLs established in R8. R11 – The SOLs established in R8 deal with future looking Operational Planning Analysis, however this requirement deals with Real-time Operations. Need clarification about Real-time Operations SOLs and we suggest the time duration for SOLs exceedances should be at least 90 minutes as described in R9.
No
R1 – No comments R2 – The word "preclude" can be interpreted as "prevent", which would mean that any exceedance of an IROL or SOL would be a violation, regardless of duration. Other wording, such as "avoid" should be considered. R3 – No comments
Yes
R1.1 - It is our understanding that bullets should be avoided in the requirements. R2 – No comments R3 – No comments R4 – No comments
No
The Time Horizons seem to be inconsistent with established NERC definitions. The VSLs need to be updated with language modified in the requirements
Individual
Michael Moltane
ITC
No
ITC thanks the SDT for their work, and believes this iteration of the standard contains improvements. However, we have the following comments and concerns. Regarding the definition of "Reliability Directive", we believe that a clarifier should be added to indicate that a Reliability Directive is "a communication initiated AND IDENTIFIED......". The addition of the words "and identified" makes very clear that the intitiating entity must identify a communication as a Reliability Directive, and thus triggering all requirements related to the Directive. Regarding R6: ITC is concerned with the requirement that impacted "NERC registered entities" be notified of certain conditions. This puts the operating personnel in the position of having to consult the NERC Registry every time an event or action covered in this requirement occurs. Recognizing that is is not an optimal use of our operating personnel, we believe that "NERC registered" should be struck and therefore the requirement would simply require notification of "...negatively impacted interconnected entities". Regarding R8: ITC is concerned that this requirement essentially raises SOL to the same level as an IROL, which of course they should not be. We also share DECs concerns regaring this requirement that TOP actions for local reliability should not be in a mandatory reliability standard. To quote from the DEC submitted comments: "In the Consideration of Comments the drafting team acknowledges that the intent of the requirement is to allow a TOP to go beyond what is needed to support BES reliability, and address local load concerns. We believe such a requirement has no place in a mandatory reliability standard, because an entity can always do more than what is required. The inclusion of the concept of "supporting internal area reliability", creates compliance risk which we believe is unnecessary and is not supported by Section 215 of the Federal Power Act. Auditors could potentially find an entity non-compliant if no SOLs have been identified as "supporting its internal area reliability", a nebulous and undefined term. Consistent with our argument on this requirement, we also question how the drafting team was able to justify a "Medium" VRF. It very clearly doesn't meet the guidelines." [End DEC comment quote]. ITC further concurs with the MRO NSRF submitted comments that "SOL's must either be removed from consideration, or more narrlowly defined to the appropriate set of SOL's that directly impact the reliability of the BES (cause instability, uncontrolled seperation, or cascacing outages)."
No
Regarding R3: Consistent with our comments on TOP-001 R6, we believe that the use of the word "registered" entities does not provide value, and only adds an unnecessary administrative step to operating personnel. We recommend just using "entities".
No
ITC is concerned with the removal from R1.1 of the phrase "...at the discretion of the Transmission Operator or Balancing Authority". Why was this removed? The TO and BA should have descretion of what data it needs (especially at the sub-BES level) to perform Operational Planning Analysis and Real time monitoring. Also in R1.1, please define what "long-term outages" are.

Group
ISO/RTO Standards Review Committee
Albert DiCaprio
No
The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which “have been identified as supporting internal area reliability” within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. The SRC proposes the following changes: R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] Delete the following requirement entirely--- R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] new R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] new R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s Tv, or of an SOL identified in Requirement R8 within [DELETE 30 minutes] the time specified by the Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations] There doesn’t seem to be a need for R9 since this is covered in R11.
Yes
No
The second bullet under R1, 1.1 facilities “at voltage levels lower than the BES;” we believe that these facilities are not enforceable under the NERC Standards. We believe any such references should be removed. We suggest removing this phrase from the bullet.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
No comments
No comments
No
The need for the proposed “overarching” document is not necessary and appears cumbersome for many regions of the country such as the western interconnect.
No
We concur with the WECC recommendations as stated in the WECC Position Paper for the initial ballot of Project 2007-03 – Real-time Operations as follows: TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs do not appear to address the situation where the responsible entity did not include three or more of the required elements of the documented specification for the data necessary for it to perform its required Operations Planning Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?

No comments
Individual
Kathleen Goodman
ISO New England Inc.
No
The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which “have been identified as supporting internal area reliability” within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. We propose the following changes: R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. Delete the following requirement entirely--- R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.---There doesn’t seem to be a need for this is covered in R11. Formerly R10, new R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. Formerly R11, new R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s Tv, or of an SOL identified in Requirement R8 within [DELETE 30 minutes] the time specified by the Transmission Operator.
Yes
No
The second bullet under R1, 1.1 facilities “at voltage levels lower than the BES;” we believe that these facilities are not enforceable under the NERC Standards. We believe any such references should be removed. We suggest removing this phrase from the bullet.
Group
Florida Municipal Power Agency
Frank Gaffney
No
R5 requires communications / coordination more than the version 1 standard (old R7) to those actions that can result in an Adverse Reliability Impact, which are very few and is ambiguous. FMPA suggests adding the phrase “or cause an SOL or IROL to be exceeded” to the requirements, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact or cause an SOL or IROL to be exceeded on those respective Transmission Operator Areas …." Also, there seems to be overlap of responsibility with the RC in real-time operations concerning SOLs and IROLs. FMPA can certainly see informing the RC and neighboring TOPs of a potential SOL / IROL in an Operational Planning Assessment, but, in real-time, that may be too much of a burden and might step on the RC’s toes in efficient and effective communication and coordination. R7 is ambiguous as to whether the IROL and IROL Tv are IROLs identified in real-time or identified through Operational Planning Analysis. R7 should be treated in a similar manner to R9 and refer to those IROLs identified through the Operational Planning Analysis. The concern is that if an extreme contingency occurs beyond what is in the scope of the Operational Planning Analysis, and that extreme contingency causes an IROL with a very short Tv in real-time, will the TOP be able to comply? R8 belongs in TOP-002-3 since it is Operational Planning Analysis. R11 seems to create double jeopardy with R7 and R9. R11 should be deleted and the concepts embedded in R11, such as “direct others” and “limit the magnitude and duration”, ought to be included in R7 and R9 instead.
No
The prior version 2 standard was applicable to both the BA and the TOP. The new standard is just the TOP, which is appropriate; however, it was the old TOP-002-1 that basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed to meet the next

day’s peak load plus ancillaries (at least that's how we interpreted R5, R6, R7 and R9 of the version 2 standard and how they would apply to a BA). BAL-002-0 requires that a BA have enough contingency reserves, but, it is unclear as to whether a BA is permitted to shed load to achieve those reserves, and how regulation service and frequency reserves are handled. FMPA suggests that TOP-002-3 include a temporary requirement for BA’s to plan to meet the current day / next day projected peak loads plus reserve requirements until it is included in the BAL standards and at which time the requirement in the TOP standards could be retired. Operational Planning Analysis is ambiguous. R1 doesn't talk about the time frame of operations planning. The old version clearly had current day, next day and seasonal operations planning requirements that probably ought to be retained, as opposed to the ambiguous phrasing of R1. It also does not talk about what is being studied, e.g., the same contingencies included in the RC SOL methodology of FAC-011 for instance. FMPA suggests defining the capitalized term of Operational Planning Analysis and add it to the NERC Glossary, especially since it is a capitalized term in the standard. R2 is confusing. We are sure the intent is that, if the Operational Planning Analysis results show that an SOL or IROL would be exceeded as a result of single / double contingencies covered by the RC’s SOL Methodology of FAC-011, then the TOP must develop a plan to resolve the situation within the Tv of the SOL or IROL. FMPA recommends that the SDT redraft R2 to make it less confusing and add clarity, maybe something like: “Each TOP shall develop plans to relieve an SOL or IROL violation identified in the results of Operational Planning Analyses within the time constraints related to the SOL or IROL (e.g., within the time frame of emergency ratings or the IROL Tv)” Such a change will also help clarify which entities are notified in R3. Currently, R3 is ambiguous as well since R2 as currently drafted seems to indicate that the Operational Planning Analysis itself if the plan, and since everyone has a role in that plan, then R3 seems to indicate that everyone needs to be notified, which we doubt is the intent of the SDT.
No
R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards. It would also be beneficial to split this requirement into two requirements, one for real-time and one for Operational Planning Analysis since they are separate databases. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: (i) Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ...."; hence, the second use of Facilities in the phrase ought to be deleted, or at minimum, replaced with the term Elements; and (ii) although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 "mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. FMPA suggests clarifying who is mutually agreeing. Also, from a reliability perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14. R1.3 and R1.4 - should have the same characterization of R1.2, e.g., "mutually" or stakeholder process driven to establish a schedule.
No
FMPA has no comments on the VRFs FMPA believes significant changes to the standards are required; hence, it is too early to opine on the VSLs.
Group
PPL Supply
Annette Bannon
No
While PPL Generation and EnergyPlus generally agrees with the changes that were made, we do not feel the standard is ready for balloting based on the following comments: R1 and R2 – In both requirements, notification of the TOP is required and appears to be for the same condition. If this is not so, the requirements need to be more specific regarding the reasons for notification. For example, R1 appears to require notification for specific conditions regarding violations of safety, equipment,

regulatory or statutory requirements and R2 could be interpreted that after agreeing to and during the course of complying with a reliability directive, the entity was unable to do so. PPL Generation and EnergyPlus does not believe that these two requirements need to be separated. Moreover, to the extent there are duplicative requirements for the same issue, if a violation were to occur, an entity may be in violation of two requirements instead of one. The standards must clearly state what is required and must do so without creating duplicative or overlapping requirements or sub-requirements. As presently drafted, R1 and R2 create confusion as to what is required and could result in multiple self reports for the same potential violation and potentially additional penalties as a result of two violations for what appears to be the same issue. R3 – This requirement appears to be an operational planning requirement and may more appropriately be inserted in TOP-002-3. If it remains in this standard, we suggest the following wording: Each TOP shall inform its RC and all other TOPs that are expected to be affected by anticipated emergencies based on its operational planning analysis. PPL Generation and EnergyPlus thinks “assessment” is synonymous with “analysis”). We also believe that R5 is intended to cover real-time operations. The time horizons do not appear to match the requirement, i.e., Operations Planning. R4 – No comments R5 – PPL Generation and EnergyPlus recommend similar language to that in R3 for consistency and clarity, i.e., R3 has “all other transmission operators” and R5 has “other Transmission Operators”. The requirement is unclear in describing who is responsible for informing whom, needs to be rewritten to clarify. R6 – What is meant by “associated communication channels”? Data or Voice or both? Is this not covered by the COM Standards? Additionally, please clarify what is intended by terms “negatively impacted interconnected NERC entities” and “control equipment” as used in proposed R6. R7 – No comments R8 – The use of Operational Planning Analysis in this requirement is not consistent with the Time Horizon of Real-time Operations. Based on the NERC definition Operational Planning Analysis is considered future looking (next-day through 12 months) this would exclude modification to SOLs made during Real-time Operations. SOLs utilized in Operational Planning Analysis are based on certain assumptions given forecasted conditions or historical data. Real-time operating conditions can vary drastically from these assumptions and there needs to be flexibility in modifying SOLs to account for these actual system conditions. R9 – The 30 minute duration is quite restrictive in resolving an SOL exceedance, especially for those that are considered to support internal area reliability. Does this apply only to actual SOL exceedances, or does it also include post-contingent SOL exceedances? PPL Generation and EnergyPlus feel the time limit should be at least 90 minutes for exceeding an SOL (especially for post-contingent SOLs), to allow for use of TLR procedures or other measures which often take more than 30 minutes to implement. There needs to be some flexibility in establishing Real-time Operations SOLs based on actual system conditions separate from the Operational Planning Analysis. R10 – Because the Time Horizon is “Real-time Operations” the SOLs communicated to the RC per this requirement should be the Real-time Operations established SOLs, not the Operational Planning Analysis SOLs established in R8. R11 – The SOLs established in R8 deal with future looking Operational Planning Analysis, however this requirement deals with Real-time Operations. Need clarification about Real-time Operations SOLs and we suggest the time duration for SOLs exceedances should be at least 90 minutes as described in R9.
No
R1 – No comments R2 – The word “preclude” can be interpreted as “prevent”, which would mean that any exceedance of an IROL or SOL would be a violation, regardless of duration. Other wording, such as “avoid” should be considered. R3 – No comments
Yes
R1.1 - It is our understanding that bullets should be avoided in the requirements. R2 – No comments R3 – No comments R4 – No comments
No
The Time Horizons seem to be inconsistent with established NERC definitions. The VSLs need to be updated with language modified in the requirements.
N/A
Group
Luminant Energy
Jeff Longshore
Yes

Yes
No
While we agree with the concept of the TOP and BA creating a specification for data necessary for Operational Planning and Real-time monitoring, we feel that Requirement 1.2 should explicitly state that the format should be mutually agreeable to the TOP and BA and the parties receiving the data request under R2 and R3. Additionally, for R1.3, we feel the same mutually agreeable requirement between the TOP and BA and the parties receiving the data request should be added for the periodicity requirement.
Yes
Individual
Brenda Pulis
Oncor Electric Delivery
No
For TOP-001, Oncor does not believe that the proposed language will provide a coordinated communication effort in the event of a planned outage of telemetry, control equipment and associated communication channels. In addition, the term “negatively impacted interconnected registered entities” is too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity.
Yes
Yes
Yes
Individual
Michael Falvo
Independent Electricity System Operator
No
In Requirement R2, there is a need to specify how much time should be allowed to “inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator.” Suggest rewording R2 to read: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall immediately inform its Transmission Operator of its inability to perform a Reliability Directive. In Requirement R4, we suggest the following rearrangement of the sentence to improve readability: R4: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures. In Requirement R8, we suggest replacing “internal area” with “BES” for greater clarity. The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which “have been identified as supporting internal area reliability” within 30 minutes should be modified to allow the TOP and RC to determine the appropriate timeframe for correcting such exceedances. We suggest the following alternative wording for Requirements R8 to R11. Additionally, we suggest removing R9 since its provisions are already covered in R11. R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its BES reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in

Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within the time specified by the Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]
Yes
No
Referring to the second bullet under R1, Part 1.1, "...Facilities at voltage levels lower than the BES;" these facilities are not enforceable under the NERC Standards. Any such references should be removed. Editorial comment: remove M5 because there is no corresponding R5.
No
Referring to the Moderate and High VLSs for TOP-001-2 Requirements R3, R5, R6 and R8, where these VLSs state "...more than x% or less than or equal to y%...", suggest changing to ""...more than x% and less than or equal to y%...". These changes would also make these VLSs consistent with the language of TOP-002-3 and TOP-003-2.

Consideration of Comments

Real-Time Transmission Operations — Project 2007-03

The Real-Time Transmission Operations Drafting Team thanks all commenters who submitted comments on the 5th draft and initial ballot of the standards for Real-Time Operations (Project 2007-03). The standard and associated documents were posted for a 45-day public comment period from April 26, 2011 through June 9, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special Electronic Comment Form. There were 44 sets of comments, including comments from approximately 156 different people from approximately 97 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

TOP-001-2:

- Changed the title of the standard to 'Transmission Operations' to better reflect the content of the standard.
- Based on Quality Review feedback changed the Purpose of the standard to more fully align with the requirements of the revised standard.
- Revised Requirement R1 to note that a Reliability Directive should be identified as such
- Deleted 'upon recognition' from Requirement R2
- Deleted 'all other' from Requirement R3
- Added Reliability Coordinator to Requirement R5
- Deleted Generator Operator from Requirement R6 and clarified that the requirement was for 'telemetry equipment'
- Deleted the 30 minute limit from Requirement R9 and replaced it with references to Facility Rating and Stability criteria
- Deleted the 30 minute limit from Requirement R11 to correspond with the change in Requirement R9
- Made a semantic change for clarity to Measure M2
- Changed the Time Horizons for Requirements R3, R5, and R8
- VSLs for Requirements R3, R5, and R6 were changed to move away from percentages

- The language for the VSLs in Requirements R2, R6, & R8 was clarified
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-002-3:

- Revised Requirement R2 to read as a positive statement rather than as a double negative
- Added the term “NERC” as a modifier of “registered entities” in Requirement R3
- Changed the VRF for Requirement R3 to Medium
- Modified the VSLs for Requirement R1
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-003-1:

- Based on Quality Review feedback, the Purpose of the standard has been modified to more fully align with the requirements of the revised standard.
- The bullets under Requirement R1, Part 1.1 have been deleted.
- Added new Requirement R2 to separate out the responsibilities of Balancing Authorities from Requirmeent R1.
- In response to Quality Review feedback, modified the language in Requirements R3 and R4 to clarify which data the Transmission Operator and Balancing Authority are to distribute.
- Made conforming changes to Measures to reflect changes to the Requirements.
- Based on Quality Review feedback, modified the Data Retention section to reflect the current NERC Rules of Procedure and Drafting Team Guidelines for evidence retention.
- Made conforming changes to VSLs to reflect changes to Requirements.

Other changes:

- The definition of Reliability Directive has been modified by Project 2006-06 to read as follows:

  “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.”

Minority opinions expressed at this point include:

- There is still some debate as to what is meant by internal area reliability. The SDT continues to believe, as stated in previous responses, that the Transmission Operator is best suited to determine what affects its internal area and the resolution of those issues are best left to the Transmission Operator.
- Questions arose about the role of the Balancing Authority in the actions described in the revised TOP standards. The SDT has clearly defined each element of responsibility that was previously defined for the Balancing Authority in the existing TOP standards and how it was handled in the revised TOP standards. The SDT does not believe that any gaps have been created by the revisions.
- Some commenters continue to debate the treatment of internal area reliability related SOLs in the same manner as IROLs.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Gerald Beckerle	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Larry Rodriquez	Entegra Power	SERC	5
2.	Bill Autrey	Alabama Power	SERC	1, 3, 5
3.	Jake Miller	Dynegy	SERC	5, 6
4.	Scott Brame	NCEMCS	SERC	1, 3, 5, 9
5.	Jeff Harrison	AECI	SERC	1, 3, 5
6.	Mike Hardy	Southern	SERC	1, 3, 5
7.	Robert Thomasson	BREC	SERC	1, 3, 5, 9
8.	Chris Bolick	AECI	SERC	1, 3, 5
9.	Shardra Scott	Gulf Power	SERC	1, 3, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10. John Troha		SERC	SERC 10										
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	1
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	1
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Connie Lowe	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Crowley		SERC	1
2.	Louis Slade		RFC	5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

3.	Mike Garton		MRO	5, 6
4.	Michael Gildea		NPCC	5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Patricia Robertson	BC Hydro	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vinnakota Venkataramakrishnan	BC Hydro	WECC	2
2.	Pat G Harrington	BC Hydro	WECC	3
3.	Clement Ma	BC Hydro	WECC	5
4.	Daniel W O'Hearn	Powerex Corp.	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Mikhail Falkovich	Public Service Enterprise Group LLC	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Clint Bogan		NPCC	5, 6
2.	Ken Brown		RFC	1
3.	Jeffery Mueller		RFC	3
4.	Peter Dolan		RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jim Keller	Wisconsin Electric Power Company			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Linda Horn	Wisconsin Electric Power Company	RFC	5
2.	Tony Jankowski	Wisconsin Electric Power Company	RFC	4

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Joe O'Brien	NIPSCO	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kevin Largura	NIPSCO	RFC	1
2.	Bill Sedoris	NIPSCO	RFC	3
3.	Bill Thompson	NIPSCO	RFC	5
4.	Joe O'Brien			6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tedd Snodgrass	BPA, Transmission Dispatch	WECC	1
2.	Tim Loepker	BPA, Transmission Dispatch	WECC	1
3.	John Anasis	BPA, Transmission Technical Operations	WECC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

4. Steve Larson	BPA, Legal Office	WECC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Jesus Sammy Alcaraz	Imperial Irrigation District	X		X	X						

Additional Member	Additional Organization	Region	Segment Selection
1. Tino Zaragoza	IID	WECC	1
2. Jesus Sammy Alcaraz	IID	WECC	3
3. Diana Torres	IID	WECC	4
4. Cathy Bretz	IID	WECC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. John Reed	FE	RFC	1
2. Ralph Cannon	FE	RFC	1
3. Ken Dresner	FE	RFC	5
4. Brian Orians	FE	RFC	5
5. Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
6. Rusty Loy	FE	RFC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Carol Gerou	MRO's NERC Standards Review Forum										X

Additional Member	Additional Organization	Region	Segment Selection
1. Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2. Chuck Lawrence	American Transmission Company	MRO	1
3. Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4. Jodi Jenson	Western Area Power Administration	MRO	1, 6
5. Ken Goldsmith	Alliant Energy	MRO	4
6. Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7. Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8. Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10. Scott Nickels	Rochester Public Utilties	MRO	4
11. Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
12. Marie Knox	Midwest ISO Inc.	MRO	2
13. Lee Kittelson	Otter Tail Power Company	MRO	1, 3, 4, 5

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

14.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
17.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Brent Ingebrigtson	LG&E and KU Energy			X							

No additional members listed.

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Albert DiCaprio	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	RFC	2
2.	Patrick Brown	PJM	RFC	2
3.	Greg Campoli	NY ISO	NPCC	2
4.	Mike Falvo	IESO	NPCC	2
5.	Matt Goldberg	ISO NE	NPCC	2
6.	Kathleen Goodman	ISO NE	NPCC	2
7.	Ben Li	IESO	NPCC	2
8.	Steve Myers	ERCOT	ERCOT	2
9.	Bill Phillips	MISO	RFC	2
10.	Mark Thompson	AESO	WECC	2
11.	Mark Westendorf	MISO	RFC	2
12.	Charles Yeung	SPP	SPP	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
3.	Jim Howard	Lakeland Electric	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Electric Utility	FRCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Annette Bannon	PPL Supply					X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

1.	Lower Mount Bethel Energy, LLC	RFC	5
2.	PPL Brunner Island, LLC	RFC	5
3.	PPL Holtwood, LLC	RFC	5
4.	PPL Martins Creek, LLC	RFC	5
5.	PPL Montour, LLC	RFC	5
6.	PPL Montana, LLC	WECC	5
7.	PPL EnergyPlus, LLC	MRO	6
8.	PPL EnergyPlus, LLC	NPCC	6
9.	PPL EnergyPlus, LLC	RFC	6
10.	PPL EnergyPlus, LLC	SERC	6
11.	PPL EnergyPlus, LLC	SPP	6
12.	PPL EnergyPlus, LLC	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Individual	Jeff Longshore	Luminant Energy						X				
17.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
18.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
19.	Individual	Mike Laney	Luminant Power					X					
20.	Individual	Antonio Grayson	Southern Company	X		X							
21.	Individual	Chang Choi	City of Tacoma or Tacoma Public Utilities	X		X	X	X	X				
22.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
23.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
24.	Individual	Thad Ness	American Electric Power	X		X		X	X				
25.	Individual	Larry Grimm	Texas Reliability Entity										X
26.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
27.	Individual	Jim Howard	Lakeland Electric	X		X		X	X				
28.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
29.	Individual	Rex Roehl	Indeck Energy Services					X					
30.	Individual	Darryl Curtis	Oncor Electric Delivery	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
31.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
32.	Individual	David Thorne	Pepco Holdings Inc	X		X							
33.	Individual	Kirit Shah	Ameren	X		X		X	X				
34.	Individual	Anthony Jablonski	ReliabilityFirst										X
35.	Individual	Denise Lietz	Puget Sound Energy	X		X		X					
36.	Individual	Jennifer Eckels	Colorado Springs Utilities	X		X		X	X				
37.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
38.	Individual	Jason Snodgrass	Georgia Transmission Corporation	X									
39.	Individual	Bill Keagle	BGE	X									
40.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
41.	Individual	Michael Moltane	ITC	X									
42.	Individual	Kathleen Goodman	ISO New England Inc.		X								
43.	Individual	Brenda Pulis	Oncor Electric Delivery	X									
44.	Individual	Michael Falvo	Independent Electricity System Operator		X								

1. **The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: In response to comments, Requirements R1, R2, R3, R5, R6, R9, and R11 were changed, along with conforming changes to the respective measures. Measure M2 was also changed in response to a specific comment. Conforming changes were made to the respective VSLs. These changes mitigated apparent double jeopardy, clarified Reliability Directives, and removed references to 30 minutes as the time limit for correcting the exceedence of an SOL.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

M2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified Reliability Directive(s) issued in accordance with Requirement R2.

M5. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5 unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

Organization	Yes or No	Question 1 Comment
Duke Energy Duke Energy Carolina	No	We disagree with the revised definition of Reliability Directive. The phrase “or expected” creates compliance uncertainty and should be struck. o R8 - We have made this comment before and continue to strongly believe that the phrase “supporting its internal area reliability” should be replaced with the phrase “having an Adverse Reliability Impact”. In the Consideration of Comments the drafting team acknowledges that the intent of the requirement is to allow a TOP to go beyond what is needed to support BES reliability, and address local load concerns. We believe such a requirement has no place in a mandatory reliability standard, because an entity can always do more than what is required. The inclusion of the concept of “supporting internal area reliability”, creates compliance risk which we believe is unnecessary and is not supported by Section 215 of the Federal Power Act. Auditors could potentially find an entity non-compliant if no SOLs have been identified

Organization	Yes or No	Question 1 Comment
		as “supporting its internal area reliability”, a nebulous and undefined term. Consistent with our argument on this requirement, we also question how the drafting team was able to justify a “Medium” VRF. It very clearly doesn’t meet the guidelines. o R9 - The VRF has been changed from “High” to “Medium”. Consistent with our previous comment on R8, we question how the drafting team was able to justify a “High” or “Medium” VRF. It very clearly doesn’t meet the guidelines. o R11 - Including the SOLs identified in R8 in this requirement effectively makes those SOLs equivalent to an IROL for mitigation purposes. Consistent with our comments above on R8 and R9, our concern is that under this approach all equipment ratings could potentially become SOLs subject to the same mitigation as IROLs.

Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for recirculation ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. The Transmission Operator may anticipate an Emergency condition without having a declared Emergency. No change made.

R8: The SDT reminds the commenter that the Transmission Operator retains responsibility for SOLs. This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase ‘internal area reliability’ was left undefined to encompass each of these unique challenges. No change made.

R9: The SDT believes the Medium VRF is appropriate for TOP-001-2, Requirement R9 as the SOLs that are identified by the Transmission Operator are important SOLs. To have a lower VRF, the requirement would have to be administrative in nature per the definition of VRF. No change made.

R11: The SDT agrees the subset of SOLs identified are treated the same as IROLs because they have been identified by the Transmission Operator itself as needing special treatment. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made.

Organization	Yes or No	Question 1 Comment
Ameren	No	(1)We do not agree with the definition of “Reliability Directive”. The phrase “expected” Emergency creates uncertainty and will create controversy. We suggest to remove the “actual or expected” phrase, and instead add “... condition or situation that threatens the reliability of the Bulk Electric System and is likely to lead to cascading, separation, islanding, ...” after emergency consistent with the intent of the FPA and NERC Standards. (2) In R2, the SDT uses the adjective "identified" which, in the Compliance and Enforcement arena, unfortunately may imply a new and different type of Directive (an "identified Reliability Directive"). We assume the SDT meant to imply with the word "identified", that the TOP would let know the receiving party explicitly that the communication that they were receiving was in fact a Reliability Directive and not just some other form of operating communication. IF that is the case, we suggest that the SDT simply state that fact as follows, "A Directive issued by a TOP which is referred to in the ensuing 3-way communication with the recipient of that Directive using the specific words Reliability Directive". (3)In R6, we have concerns with the Generator Operator having to “notify negatively impacted interconnected NERC registered entities of planned outages of telemetry...” etc. This is too broad for a GOP to be lumped in with the TOP and BA, since most GOPs do not have the knowledge if these planned outages would negatively affect other NERC entities. We believe that R6 should apply to TOP and BA, and maybe have R6.1 that requires the GOP to notify their specific TOP and BA of planned outages of telemetry, control equipment, and communication channels which in turn would generate communication from the host TOP and BA to others so affected. (4) In R8, what is meant by “internal” area reliability? We have a significant concern form a compliance perspective about how would it be interpreted and audited. (5) R11 refers to R8 and SOL. Is it the intent of the SDT to consider SOL effectively the same as IROL for purpose of this requirement?
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. The Transmission Operator may anticipate an Emergency condition without having a declared Emergency. No change made.		

Organization	Yes or No	Question 1 Comment
The wording of Requirement R1 has been altered to add the term "identified" which will now tie to Requirement R2. **R1.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The SDT has modified Requirement R6 to eliminate the Generator Operator as TOP-003-2 covers the situation of providing this data to the Transmission Operator and Balancing Authority which are the only two entities with which the Generator Operator must communicate. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. The SDT reminds the commenter the Transmission Operator retains responsibility for SOLs. This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase 'internal area reliability' was left undefined to encompass each of these unique challenges. No change made. The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made.		
Occidental Chemical	Ballot Comment	1. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 0 Yes 1 No Comments:Ingleside Cogeneration LP agrees with most of the concepts and language the SDT is driving to in TOP-001-2. However, there are two items which we believe require further exploration before we can vote in favor of the standard. First, requirements R1 and R2 present a double-jeopardy to a GOP if a front line operator does not inform the TOP of an inability to comply with an identified Reliability Directive that violate safety, equipment, regulatory, or statutory requirements. The requirements can be modified as shown below to capture the same intent without having two high VRF assessments for the same incident. R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability

Organization	Yes or No	Question 1 Comment
		Directive issued by its Transmission Operator, [delete: unless the respective entity informs its Transmission Operator that - end delete] such actions would violate safety, equipment, regulatory, or statutory requirements. R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. Second, the concept of moving all operational data requirements - including outage notifications - to a single standard (TOP-003-1) is a useful consolidation of many similar requirements. We believe that it can be logically extended to include the notification of telemetry and control equipment outages which now fall under R6. Furthermore, TOP-003-1 requires the creation of a data specification and reporting criteria - which is far more specific than the open-ended language used in R6. 2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 Yes 0 No Comments: From a GO/GOP perspective, Ingleside Cogeneration LP agrees that a significant amount of redundancy has been removed by consolidating requirements to coordinate day-of, next-day, and seasonal operations under TOP-003. The same is true of the requirement to perform real and reactive capacity validations - which are addressed in the MOD standards. 3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 Yes 0 No Comments: Ingleside Cogeneration LP strongly supports the consolidation of TOP and BA operations data requirements into a single specification. In addition, the Project Team has correctly recognized that web-based portals and similar applications are becoming more prevalent - and should be encouraged as an effective means to distribute operations information.

Organization	Yes or No	Question 1 Comment
Response: The SDT agrees and has made changes to the requirements to address your concerns. **R1.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R2.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. The SDT has modified Requirement R6 to eliminate the Generator Operator as TOP-003-2 covers the situation of providing this data to the Transmission Operator and Balancing Authority which are the only two entities with which the Generator Operator must communicate. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
Colorado Springs Utilities	No	Colorado Springs Utilities appreciates the opportunity to comment on this draft and the changes made to this standard. The following comments are specific to requirements R3,R4, R8/R10,R9, & R11. R3. By changing "of" to "by" there is now no object to the verb "inform". Suggested language: "Each Transmission Operator shall share its assessment of its Operational Planning Analysis with its Reliability Coordinator, and all other Transmission Operators that are known or expected to be affected, based on that assessment, by actual and anticipated Emergencies." R4. Colorado Springs Utilities agrees with those who have commented on previous drafts that the language strongly implies that the TOP rendering assistance is obligated to ensure the entity receiving assistance has implemented "comparable emergency procedures." We recommend the requirement be rewritten: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Transmission Operator requested to provide such assistance may require that the requesting entity first implement its own comparable emergency procedures.” R8/R10. SOLs, which are not IROLs, by definition, do not impact interconnection reliability and should be the responsibility of the TOP, not the RC, and therefore should not require being reported to nor monitored by the

Organization	Yes or No	Question 1 Comment
		RC. R9. Does R9, as written, prevent the TOP from employing the option to permit equipment life reduction to avoid load shed? R11. Despite the SDT's clarifying comments provided during previous comment periods, this requirement continues to appear duplicative to R7 & R9 and seems to provide opportunity for double jeopardy in the event of non-compliance with one of those requirements. We suggest R11 be eliminated. If exceeding the SOL or IROL is remedied and restored within the required time frame, then the operator or the system has taken appropriate mitigating action.
Response: The suggested language for Requirement R3 was not accepted. This was the only comment on Requirement R3 from the ballot pool and the wording change is a style suggestion, not an improvement to reliability. No change made. The suggested language for Requirement R4 was not accepted. The meaning of "...provided that the requesting entity has implemented its comparable emergency procedures,...." is clear and unambiguous. No change made. Requirements R8 and R10 were added due to comments from a significant portion of the industry during the extensive posting process of these standards. The change has not been accepted. R9: This requirement is confined to that subset of SOLs that are important to internal area reliability as identified in the Operational Planning Analysis. It does not prohibit the adoption of an emergency rating that sacrifices equipment life. FAC-008-1 requires each Transmission Owner and Generator Owner to have a methodology for Facility Ratings that includes (R1.3): "Consideration of the following: R1.3.1. Ratings provided by equipment manufacturers. R1.3.2. Design criteria (e.g., including applicable references to industry Rating practices such as manufacturer's warranty, IEEE, ANSI or other standards). R1.3.3. Ambient conditions. R1.3.4. Operating limitations. R1.3.5. Other assumptions." Requirements R9 and R11 were modified to address other comments related to the 30 minute limit. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. R11: This requirement does not create double jeopardy. Requirement R11 is mandating that you take action to avoid a violation of Requirements R7 and R9. No change made.		
Cowlitz County PUD	No	Cowlitz respectfully disagrees with the SDT concerning requirements R1 and R2 addressing priori prohibitions and post-agreement to comply with an identified Reliability Directive. Cowlitz can see no Reliability difference between

Organization	Yes or No	Question 1 Comment
		an immediate "priori" and post-agreement identification of a TOP Reliability Directive action that would violate safety, equipment, regulatory, or statutory requirements. In each case the outcome is the same: the action is not complied with due to an inability to perform, and the TOP is informed "upon recognition." Therefore R1 and R2 are effectively duplicitous in this regard. Cowlitz suggests that the verbiage "...the respective entity informs its Transmission Operator that..." be removed from requirement R1. Cowlitz agrees with the SDT concerning "Reliability Directive" is not meant to equate to the urgency of a situation. This standard establishes the authority of the TOP to issue directives, and clear communication of such authority has been requested by this commenter in the past. Cowlitz applauds the SDT's stand on this issue. On all other matters, Cowlitz either agrees or abstains with the SDT.
Commonwealth of Massachusetts Department of Public Utilities	Ballot Comment	Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations] "upon recognition" seems problematic and further work needs to be done on this requirement to ensure that the proper intent is codified. The intent we believe to be "..immediately upon recognition of the inability to perform a Reliability Directive "within the stipulated or understood timeframe" would result in informing the TO. The concern exists that an entity might be able to perform the directive but may not within the proper timeframe of the TOPs need.
Response: The SDT agrees and has made changes to the requirements to address your concerns. **R1.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R2.** Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
Electric Market Policy	No	Dominion reads R1 to require an entity to 'carry out' the Reliability Directive. In order to comply with the requirement it must either take actions as prescribed in the Reliability Directive or it must inform the TOP that it can't do so for one of

Organization	Yes or No	Question 1 Comment
		the following: safety, equipment, regulatory or statutory requirements. It is Dominion's expectation that an entity may know whether it has safety, equipment, regulatory, or statutory conflicts with the Directive at the time the Reliability Directive is issued, but this may not always be the case (This is especially true where the Reliability Directive is issued to personnel in a control center as opposed to being directly communicated to the operator of the Element or Facility.) Regardless, whenever an entity determines it can't comply with the Reliability Directive, it must make notification or be non-compliant with R1. When the Reliability Directive has a time component and the entity doesn't comply with the time required, it is non-compliant if it hasn't completed the action(s) required unless it notified the TOP before the time component of the Reliability Directive expires (citing one of the following; safety, equipment, regulatory, or statutory requirements.) This time element guidance is not provided with this standard.
Response: R1 and R2: The SDT expects that Reliability Directives will have a time requirement. If a recipient of a Reliability Directive cannot comply due to the reasons stated in Requirement R1, then it is compliant with Requirement R1. If it does not, however, notify the issuer of its inability to comply, it is non-compliant with Requirement R2. No change made.		
Oncor Electric Delivery	No	For R6- Oncor does not believe that the proposed language will provide a coordinated communication effort in the event of a planned outages of telemetry, control equipment and associated communication channels. In addition, the term "negatively impacted interconnected registered entities" is too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity.
Response: The SDT has modified Requirement R6 to eliminate the Generator Operator as TOP-003-2 covers the situation of providing this data to the Transmission Operator and Balancing Authority which are the only two entities with which the Generator Operator must communicate. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
Southern Company Generation	Ballot	For TOP-001-2: 1) R2 and M2 are confusing due to a mismatch in using

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td>Comment</td><td>“issued” and “identified”. R2 lists the directive as “identified”, while M2 lists it as “issued, identified,”. It is suggested that the following phrasing be used: “an issued Reliability Directive” or “an identified Reliability Directive”

2) The use of a comma after “control equipment” in the list in R6 would make it easier to understand this requirement. (suggestion: make it match M6).

3) Please consider merging R1 and R2 into a single requirement that requires entities to comply with directives or provide a reason to the TOP why it is unable to do so. Then, the measure could be than an entity either complied or informed the TOP of its inability to comply.</td></tr>
<tr><td colspan="3">Response: The language of Measure M2 was adjusted to eliminate this confusion.

M2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified Reliability Directive(s) issued in accordance with Requirement R2.

The SDT agrees and changed Requirement R6:

R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.

R1 and R2: The SDT agrees and has made changes to the requirements to address your concerns.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.</td></tr>
<tr><td>Detroit Edison Company</td><td>Ballot Comment</td><td>I do not agree with the inclusion of the language "and negatively impacted interconnected NERC registered entities" in R6.</td></tr>
<tr><td colspan="3">Response: The SDT disagrees with the broader context of your comment, but did delete the Generator Operator from this requirement.

R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the</td></tr>
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Organization	Yes or No	Question 1 Comment
affected entities.		
Grand River Dam Authority	Ballot Comment	In R8 we would ask that the words internal and area be left out completely and read as "Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its reliability based on its assessment of its Operational Planning Analysis. "
Response: The SDT considered and did not accept this change in wording. The adjectives are intended to provide guidance concerning the context of this requirement. No change made.		
Northeast Power Coordinating Council Hydro One Networks Inc.	No	In Requirement R2, there is a need to specify how much time should be allowed to "inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator." Suggest rewording R2 to read: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall immediately inform its Transmission Operator of its inability to perform a Reliability Directive. In Requirement R4, we suggest the following rearrangement of the sentence to improve readability:R4: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures. The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be modified to allow the TOP and RC to determine the appropriate timeframe for correcting such limits. The maintenance of Interconnection reliability and Bulk Electric System integrity is paramount, and global specifications may or may not be appropriate for a local area. Suggest modifying the appropriate wording to: within a specified time not to exceed the timeframe specified by the TOP. R9 is redundant to R11; delete R9.
Response: R2: The SDT did not accept this change. 'Immediately' is not a measurable quantity and would create auditing difficulties.		

Organization	Yes or No	Question 1 Comment
R4: The SDT does not agree the suggested wording improves readability. No change made. R9, R10 and R11: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. Requirement R11 is mandating that you take action to avoid a violation of Requirements R7 and R9. It is not duplicative to Requirement R9. No change made.		
Independent Electricity System Operator	No	In Requirement R2, there is a need to specify how much time should be allowed to "inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator." Suggest rewording R2 to read: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall immediately inform its Transmission Operator of its inability to perform a Reliability Directive. In Requirement R4, we suggest the following rearrangement of the sentence to improve readability:R4: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures. In Requirement R8, we suggest replacing "internal area" with "BES" for greater clarity. The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be modified to allow the TOP and RC to determine the appropriate timeframe for correcting such exceedances. We suggest the following alternative wording for Requirements R8 to R11. Additionally, we suggest removing R9 since its provisions are already covered in R11. R8. Each Transmission Operator shall inform its Reliability Coordinator of all

Organization	Yes or No	Question 1 Comment
		SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its BES reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within the time specified by the Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]

Response: R2: The SDT did not accept this change. 'Immediately' is not a measurable quantity and would create auditing difficulties.

The suggested language for Requirement R4 was not accepted. The meaning of "…provided that the requesting entity has implemented its comparable emergency procedures,…." is clear and unambiguous.

R8: "Internal area" is not intended to encompass the entire BES. The wording change was not accepted.

R9, R10 and R11: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

R9 was not deleted. This is a coordinated set of requirements: Requirement R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.

Organization	Yes or No	Question 1 Comment
Southern Company	No	It would be preferable to use the term “reliability entities” or at least replace the generic term “registered entities” with a listing of the Functional Model Entities that need to be notified. The use of registered entities would require reliability information to be given to marketing entities. R2 and M2 are confusing due to a mismatch in using “issued” and “identified”. R2 lists the directive as “identified”, while M2 lists it as “issued, identified, “. It is suggested that the following phrasing be used: “an issued Reliability Directive” or “an identified Reliability Directive”. Please consider merging R1 and R2 into a single requirement that requires entities to comply with directives or provide a reason to the TOP as to why it’s unable to do so. Then, the measure could be that an entity either complied with the requirement or informed the TOP of its inability to comply. I think R2 implies that there may be reasons other than safety, equipment, regulatory, or statutory restrictions that may prevent a Generator Operator from performing an identified Reliability Directive as it refers to the GOP’s “inability” to perform the action and doesn’t specifically reference these restrictions again. I agree with your comment that the best way to handle this would be to combine R1 and R2 into a single Requirement perhaps with the following wording:”R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity is unable to perform the actions required by the Reliability Directive (due to violation of safety, equipment, regulatory, or statutory requirements or other reasons) and informs its Transmission Operator upon recognition of its inability to perform the actions. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]” For R2, The question came up for what was more appropriate - issued or identified, and requested Reliability Directive was also suggested as an option. If the reason for this descriptive term is to clarify that the Transmission Operator has declared “this is a Reliability Directive”, then identified would be the more appropriate descriptive term and should be used in a consistent manner. For R6, we take issue with changing the wording from “telemetering equipment” to telemetry as the former is equipment and the latter implies data. The distinction is that under the current wording, the entity is required to coordinate the outage of the piece of equipment that telemeters data (i.e. the RTU) whereas the proposed change implies that the entity will have to

Organization	Yes or No	Question 1 Comment
		coordinate any outages of telemetered data. This could have significant implications as there may be 1000+ data points being telemetered by an RTU, and each data point may come from a unique piece of equipment in the plant. Is the intent that removal of, say, a pressure transmitter or a MW transducer from service for routine calibration requires notification to the Reliability Coordinator? For R6, Fleet Operations functioning as Generator Operator does not directly notify the RC, but interfaces instead with the PCC. Forwarding rules in GENcomm will deliver notifications to the RC. This impacts the evidence for M6, if the expectation is a direct communication. For R6, The use of a comma after “control equipment” in the list in R6 would make it easier to understand this requirement. (suggestion: make it match to M6). For R9, this is a duplicate requirement and does not add to reliability. This requirement is addressed in TOP-004-2 R1. For R10 and R11, these are duplicate requirements and do not add to reliability. These requirements are addressed in TOP-007-0.

Response: The SDT assumes you meant Requirement R6 in your first comment. This is not an issue if dealing with a marketing entity as it is only dealing with telemetry-related outages between the Transmission Operator or Balancing Authority and that entity itself. No change made.

The wording of Measure M2 has been altered to remove ambiguity from the use of the term “identified”.

> **M2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified Reliability Directive(s) issued in accordance with Requirement R2.

R1 and R2: The SDT agrees and has made changes to the requirements to address your concerns.

> **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

> **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

R6: Agreed and change made.

Organization	Yes or No	Question 1 Comment
R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R9, R10 and R11 are not redundant as this project is retiring TOP-004-2 and TOP-007-0. No change made.		
ITC	No	ITC thanks the SDT for their work, and believes this iteration of the standard contains improvements. However, we have the following comments and concerns. Regarding the definition of "Reliability Directive", we believe that a clarifier should be added to indicate that a Reliability Directive is "a communication initiated AND IDENTIFIED......". The addition of the words "and identified" makes very clear that the intitiating entity must identify a communication as a Reliability Directive, and thus triggering all requirements related to the Directive. Regarding R6: ITC is concerned with the requirement that impacted "NERC registered entities" be notified of certain conditions. This puts the operating personnel in the position of having to consult the NERC Registry every time an event or action covered in this requirement occurs. Recognizing that is is not an optimal use of our operating personnel, we believe that "NERC registered" should be struck and therefore the requirement would simply require notification of "...negatively impacted interconnected entities". Regarding R8: ITC is concerned that this requirement essentially raises SOL to the same level as an IROL, which of course they should not be. We also share DECs concerns regaring this requirement that TOP actions for local reliability should not be in a mandatory reliability standard. To quote from the DEC submitted comments: "In the Consideration of Comments the drafting team acknowledges that the intent of the requirement is to allow a TOP to go beyond what is needed to support BES reliability, and address local load concerns. We believe such a requirement has no place in a mandatory reliability standard, because an entity can always do more than what is required. The inclusion of the concept of “supporting internal area reliability”, creates compliance risk which we believe is unnecessary and is not supported by Section 215 of the Federal Power Act. Auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”, a nebulous and undefined term. Consistent with our argument on this requirement, we also question how the drafting team was able to justify a “Medium” VRF. It very

Organization	Yes or No	Question 1 Comment
		clearly doesn't meet the guidelines." [End DEC comment quote]. ITC further concurs with the MRO NSRF submitted comments that "SOL's must either be removed from consideration, or more narrowly defined to the appropriate set of SOL's that directly impact the reliability of the BES (cause instability, uncontrolled seperation, or cascacing outages)."
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. No change made. R6: The SDT disagrees with the broader context of your comment, but did delete Generator Operator from this requirement. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R8: This requirement was added due to comments from a significant portion of the industry during the extensive posting process of these standards. The requirement does not elevate SOLs to the same status as IROLs, it elevates certain, selected SOLs at the discretion of the Transmission Operator based on analysis which would seem to coincide with the thoughts expressed in the comment. The change has not been accepted.		
MidAmerican Energy Co.	Ballot Comment	MidAmerican does not agree with the SDT reasoning for applying a general industry concept of 30 minutes to SOLs. The NERC standards did not call out at 30 minute time frame for SOLs and to do so equates SOLs with IROLs. The SDT should change all SOL references to IROLs or drop the 30 minute time frame. If the SDT does not elect to drop this, they should at a minimum define a subset of non-thermal SOLs that are shown by TPL or operational studies to cause instability, uncontrolled separation, or cascading as defined by the 2005 Federal Power Act. MidAmerican does not agree with the inclusion statement of non-BES assets or assets below the defined bright line 100 kV threshold. The reference should be deleted. The NERC standards apply to 100 kV and greater assets and all assets below 100 kV should be defined as distribution by default according to the 2005 FPA act definition, unless shown by TPL and operational studies to cause instability, uncontrolled separation, and cascading.

Organization	Yes or No	Question 1 Comment
		In addition, please see the MRO NSRF comments submitted
Response: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. This comment concerns TOP-003-2, Requirement R1: The SDT agrees this bullet is not necessary and made conforming changes. However, a Transmission Operator may ask for any data that is needed to support its Operational Planning Analyses and Real-time monitoring, and that could include non-BES equipment.		
Wisconsin Electric Power Company	No	R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator, these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase “negatively impacted interconnected NERC registered entities” is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA’s of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse Reliability Impact on another’s area, hence an emergency there is somewhat circular.
Response: R3: The suggestion was not accepted. Balancing Authorities within the Transmission Operator area are informed through TOP-002-3 as it will show in the plan. Balancing Authorities outside the Transmission Operator area will be notified by their Transmission Operator.		

Organization	Yes or No	Question 1 Comment
R4: The Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made. R6: The SDT disagrees with the broader context of your comment, but did delete Generator Operator from this requirement. **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities. R10: Balancing Authorities have no responsibility for line flows. No change made. Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]* **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*		
Imperial Irrigation District	Yes	R5 - should include notification of the Reliability Coordinator involvingAdverse Reliability ImpactM1 (b) - did not comply with the indentified directive and informed the Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1.M5 - include the notification to the Reliability Coordinator known or expected to result in an Adverse Reliability Impact Transmission Operator Areas with those Transmission Operators in accordance with Requirement R5
Response: R5: Suggestion was accepted and the requirement and measure were modified accordingly. **R5**. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such		

Organization	Yes or No	Question 1 Comment
communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. **M5**. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5 unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.		
City of Green Cove Springs	Ballot Comment	R5 seems to limit communications / coordination more than the version 1 standard (old R7) to only those actions that can result in an Adverse Reliability Impact, which are very few. GCS suggests adding the phrase “or cause an SOL or IROL to be exceeded” to the requirements, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact or cause an SOL or IROL to be exceeded on those respective Transmission Operator Areas ...." R7 is ambiguous as to whether the IROL and IROL Tv are IROLs identified in real-time or identified through Operational Planning Analysis. R7 should be treated in a similar manner to R9 and refer to those IROLs identified through the Operational Planning Analysis. The concern is that if an extreme contingency occurs beyond what is in the scope of the Operational Planning Analysis, and that extreme contingency causes an IROL with a very short Tv in real-time, will the TOP be able to comply? R8 belongs in TOP-002-3 since it is Operational Planning Analysis. R11 seems to create double jeopardy with R7 and R9. R11 should be deleted and the concepts embedded in R11, such as “direct others” and “limit the magnitude and duration”, ought to be included in R7 and R9 instead. The prior version 2 standard was applicable to both the BA and the TOP. The new standard is just the TOP, which is appropriate; however, it was the old TOP-002-1 that basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed to meet the next day’s peak load plus contingency reserve requirements, frequency reserves and regulation service (at least that's how we interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). BAL-002-0 requires that a BA have enough contingency reserves, but, it is unclear as to whether a BA is permitted to shed load to achieve those reserves, and how regulation service

Organization	Yes or No	Question 1 Comment
		and frequency reserves are handled.

Response: R5: The suggested language was not included as it is redundant. The Transmission Operator is not likely to know exactly which conditions on its system may cause an IROL or SOL excursion on a neighboring system and is not responsible for the neighboring Transmission Operator systems. The proposed TOP-003-2 requires a data specification that would cover the line flow and limit data necessary for the neighboring Transmission Operator to assure reliability in its area.

R7: An IROL that emerges in real-time may not have been identified in the Operational Planning Analysis. If you don't know about it, you can't control it and wouldn't be responsible. Requirement R8 covers those IROLs that can be anticipated. No change made.

R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made.

R11: This is a coordinated set of requirements: Requirement R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation. No change made.

Regarding the removal of the Balancing Authority from Requirements R5, R6, and R7:

The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority.

The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2.

The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2.

Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.

Organization	Yes or No	Question 1 Comment
Alberta Electric System Operator	Ballot Comment	The AESO believes requirements (R9 and R11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary

Organization	Yes or No	Question 1 Comment
		rating and timing associated with each of the ratings. The AESO would also like to see the term "emergency assistance", used in R4, defined.
Response: Requirements R9 and R11: Agreed and changed. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. R4: "Emergency assistance", similar to the data specification in TOP-003-2, should not be limited to an arbitrary list included in a requirement. If the Transmission Operator has any tool, method, or solution that can be used to provide emergency assistance to a neighboring Transmission Operator, it should. For example. the Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made.		
Constellation Energy Commodities Group	Ballot Comment	The definition of Reliability Directive needs to include: The RC, TOP or BA must clearly state that "This is a Reliability Directive". This would also apply to project 2006-06.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. No change made.		
American Electric Power	No	The draft of R6 states that "Each Transmission Operator, Balancing Authority, and Generator Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetry, control equipment and associated communication channels between the affected entities." The assessment and dissemination of GOP info to the "affected entities" should be the responsibility of the local TOP and RC. It seems inappropriate to request that the GOP make these sorts of contacts, as GOPs would lack the necessary BES info to make a determination as to who should be notified.
Response: Agreed and changed.		

Organization	Yes or No	Question 1 Comment
R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
Independent Electricity System Operator	Ballot Comment	The IESO respectfully submits the following comments along with our negative vote: 1. TOP-001-2 Requirement R2: This requires each listed entity to "inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator ." We consider "upon recognition" to be unclear since there is no indication whether the expectation is for entities to inform the TOP immediately or within some defined time. We therefore suggest the alternative wording " immediately inform its Transmission Operator of its inability to perform a Reliability Directive." This wording, while still not perfect does convey an expectation regarding the timeliness of the entity's communication with the TOP. 2. TOP-001-2 Requirement R9 and R11: These set time limits within which exceedances of IROLs and SOLs indentified pursuant to Requirement R8 must be mitigated, Tv in the case of IROLs and 30 minutes in the case of SOLs. We believe prescribing 30 minutes is not appropriate for SOLs identified in R8 and suggest rewording R8, R10 and R11 as indicated below. Additionally, we suggest removing R9 since its provisions are already covered in R11. In Requirement R8, we suggest replacing "internal area" with "BES" for greater clarity. R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its BES reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within the time specified by the

Organization	Yes or No	Question 1 Comment
		Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]

Response: R2: Agreed. Requirements R1 and R2 were modified.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

R8: "Internal area" is not intended to encompass the entire BES. The wording change was not accepted.

R9, R10 and R11: The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

Requirement R9 was not deleted. This is a coordinated set of requirements: R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.

Requirement R9 is not redundant (see above). No change made.

Northern Indiana Public Service Co.	Ballot Comment	The new standard appears to treat SOLs and IROLs in a similar manner, which should not be the case. Also, in TOP-003-2 R1 1.1 the second bullet may incorrectly bring non-BES

Organization	Yes or No	Question 1 Comment
		distribution facilities into play.
Response: R11: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made. This comment concerns TOP-003-2, Requirement R1: The SDT agrees this bullet is not necessary and made conforming changes. However, a Transmission Operator may ask for any data that is needed to support its Operational Planning Analyses and Real-time monitoring, and that could include non-BES equipment.		
ISO/RTO Standards Review Committee	No	The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. The SRC proposes the following changes:R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] Delete the following requirement entirely--- R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] new R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] new R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within [DELETE 30 minutes] the time specified by the Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Real-time Operations] There doesn't seem to be a need for R9 since this is covered in R11.
ISO New England Inc.	No	The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have

Organization	Yes or No	Question 1 Comment
		been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. We propose the following changes: R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. Delete the following requirement entirely--- R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration exceeding 30 minutes.---There doesn't seem to be a need for this is covered in R11. Formerly R10, new R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. Formerly R11, new R10. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8 within [DELETE 30 minutes] the time specified by the Transmission Operator.

Response: R8: The language was considered but not accepted; however, Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees that the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings.

> **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
>
> **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.

Requirement R9 was not deleted. This is a coordinated set of requirements: R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11) , and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.

Organization	Yes or No	Question 1 Comment
Southwest Power Pool	Ballot Comment	The requirement(s) (R9, 10 and 11) that stipulate returning SOLs which "have been identified as supporting internal area reliability" within 30 minutes should be deleted, the internal procedures would identify the necessary rating and timing associated with each of the ratings. The SRC proposes the following changes: R8. Each Transmission Operator shall inform its Reliability Coordinator of all SOLs and the durations for which they can be exceeded in cases where those SOLs, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations] R9. Delete in entirety Renumber R10 to R9. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. [Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]
Response: R8: The language was considered but not accepted; however, Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. Requirement R9 was not deleted. This is a coordinated set of requirements: R11: This requirement completes the actions required to assure situational awareness and does not create double jeopardy. The SOLs must be identified to the Reliability Coordinator (Requirement R8), the Transmission Operator must not operate in excess of the rating for greater than the appropriate time limit (Requirement R9), The Transmission Operator must act or direct others to act to mitigate (Requirement R11), and finally, Requirement R10, the Transmission Operator must inform the Reliability Coordinator about the mitigation.		
Texas Reliability Entity	No	The statement "identified reliability directive" in R1 and R2, of standard TOP-001-2, would be better changed to "reliability directive." The word "identify" requires action and the standard does not specify how the "identifying " will be done. Furthermore, if the TOP is issuing a directive, it should be assumed that the

Organization	Yes or No	Question 1 Comment
		directive is a Reliability Directive unless the TOP states that it is not. This position saves time when time is of the utmost importance. The proposed wording as presented will open the door for deliberation when corrective action should be well underway.
Response: The language in Requirement R1 was altered to reduce the possibility of confusion over the word "identified". **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The other suggested changes for Requirement R1 were not accepted. The Reliability Directive was crafted to require positive identification. When time is of utmost importance, it is better for reliability to get the communications exactly right the first time.		
Great River Energy	Ballot Comment	This requirement has the potential of treating SOLs as an IROL
Response: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made.		
James A Maenner	Ballot Comment	TOP-001 R1 "identified Reliability Directive" is subjective and vague; needs to be clearer. TOP-001 R11 is troubling; it seems to elevate SOLs to IROL status. TOP-001 The language "or expected" allows too many variants; better language maybe "as indicated through system or operational studies". The language "internal area reliability" may lead to an interpretation issue and should be defined.
Response: R1: The language was changed to clarify the intent. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.		

Organization	Yes or No	Question 1 Comment
R11: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made. The requirement was not identified in the comments. Presumably this comment concerned Requirement R3. The SDT considered the suggested language but did not accept it because it does not add clarity. R8: This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase 'internal area reliability' was left undefined to encompass each of these unique challenges. No change made.		
New Brunswick Power Transmission Corporation	Ballot Comment	TOP-001 R11: "within 30 minutes" should be specified by the transmisison operator or owner. TOP-003 R1:"at voltage levels lower than the BES;" should be removed or justified on a case by case basis.
Response: Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8. This comment concerns TOP-003-2, Requirement R1: The SDT agrees this bullet is not necessary and made conforming changes. However, a Transmission Operator may ask for any data that is needed to support its Operational Planning Analyses and Real-time monitoring, and that could include non-BES equipment.		
Wisconsin Electric Power Marketing, Wisconsin Electric Power Co.	Ballot Comment	TOP-001 R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator,

Organization	Yes or No	Question 1 Comment
		these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase “negatively impacted interconnected NERC registered entities” is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA’s of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse Reliability Impact on another’s area, hence an emergency there is somewhat circular.

Response: R3: The suggestion was not accepted. Balancing Authorities within the Transmission Operator area are informed through TOP-002-3 as it will show in the plan. Balancing Authorities outside the Transmission Operator area will be notified by their Transmission Operator. No change made.

R4: The Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made.

R6: The SDT disagrees with the broader context of your comment, but did delete the Generator Operator from this requirement.

> **R6.** Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.

R10: Balancing Authorities have no responsibility for line flows. No change made.

Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this.

> **R3**. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

Organization	Yes or No	Question 1 Comment
R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*		
Lakeland Electric	No	TOP-001-2 Coordination of Transmission Operations R5 seems to limit communications / coordination more than the version 1 standard (old R7) to only those actions that can result in an Adverse Reliability Impact, which are very few. This is probably underperforming and FERC will probably not like it. Some other limits to the scope of communications, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations of Bulk Electric System Facilities known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load." I disagree with deleting TOP-008-1 R3 that allows TOPs, after exhausting other methods to alleviate the problem, to open a Facility if it is imminent danger of catastrophic failure. The requirement should be revised and included in TOP-001-2 as something like the TOP shall request permission of the RC to disconnect the Facility if there is a threat of imminent catastrophic failure, the RC can direct otherwise "unless the direction per Requirement (IRO-001-2). R2 can not be implemented or such actions would violate safety, equipment, regulatory or statutory requirements" (IRO-001-2, R3). Exceeding an IROL that might result in a system restoration event with equipment capable of being restored is preferable to waiting for a Facility to be disconnected due to catastrophic failure, still exceeding the IROL due to that disconnection, but resulting in a system restoration exercise with catastrophically failed equipment. An example of this is the 1977 blackout of NYC which was exacerbated by catastrophically failed equipment. On R7 and R9, I'm concerned about the "for how many contingencies" question, e.g., are we held to the same criteria for "extreme contingencies"? The BAL standards have exclusions for multiple contingencies in meeting the performance requirements (e.g.,BAL-002-0 D1.4). There is not such consideration for "Extreme" contingencies in R7 and R9. If a bad event occurs beyond the criteria we operate the system to, are we setting ourselves up for failure and fines?

Organization	Yes or No	Question 1 Comment
Response: The suggested language was not included as it is redundant. The Transmission Operator is not likely to know exactly which conditions on its system may cause an IROL or SOL excursion on a neighboring system and is not responsible for the neighboring Transmission Operator system. The proposed TOP-003-2 requires a data specification that would cover the line flow and limit data necessary for the neighboring Transmission Operator to assure reliability in its area. Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. The SDT reaffirms that a standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse. No change made. Requirements R7 and R9 simply state you must not operate outside IROLs and the non-IROL SOL subset. They do not define how IROLs and SOLs get created. Creation of IROLs and SOLs is governed by FAC-011-2 and FAC-014-2. FAC-011-2 establishes how contingencies must be considered including if any multiple contingencies (FAC-011-2 R3.3) must be included. No change made.		
Northeast Power Coordinating Council, Inc.	Ballot Comment	TOP-001-2 R2 states: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations] “upon recognition” seems problematic and further work needs to be done on this requirement to ensure that the proper intent is codified. The intent we believe to be “..immediately upon recognition of the inability to perform a Reliability Directive “within the stipulated or understood timeframe” would result in informing the TO. The concern exists that an entity might be able to perform the directive but may not within the proper timeframe of the TOPs need.
Response: The SDT modified Requirements R1 and R2. However, ‘immediately’ is not a measurable quantity and would create auditing difficulties. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
New Brunswick System Operator	Ballot Comment	TOP-001-2 R9, 10 and 11 that stipulates returning SOLs which “have been identified as supporting internal area reliability” within 30 minutes should be

Organization	Yes or No	Question 1 Comment
		modified to allow the TOP and RC to determine the appropriate time frame for correcting such limits.
Response: Requirements R9 and R11 were changed to comply with this suggestion. The SDT agrees the 30 minute time limit is incorrect and has changed the language to reflect that SOLs are determined by FAC-011 which sets the requirements for ratings. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.		
Lakeland Electric	Ballot Comment	TOP-001-2 The words "that are known or expected to be affected" in R3 and "known or expected to result" in R5 may seem reasonable until you look at the VSL table and question the risk of have a PV because the TOP overlooked a notification of marginal value under these requirements in the heat of battle because the condition was not expected to impact an entity.
Response: The Operational Planning Analysis points to those "expected to be affected." No change made.		
South Texas Electric Cooperative	Ballot Comment	TOPs should not be expected to notify other TOPs of problems. That should be the responsibility of the RC or the BA - whomever the TOP is reporting to should have the responsibility of consolidating reports and notifying affected entities accordingly.
Response: The Transmission Operator must coordinate with its neighbors. This is the lynchpin of coordinated operations. No change made.		
Consumers Energy	Ballot Comment	We concur with most of Duke Energy's comments. We further add that we are especially concerned with the definition of Reliability Directive which is ambiguous at best. In TOP-001-2, R2 there is a statement of "upon recognition" in dealing the informing the TO of an inability to follow a Reliability Directive. This is vague and very difficult to document. It is unfortunate but the transition to legalistic interpretations of standards, a task often defaulting to audit team personnel, makes it absolutely mandatory that the expectations for proof of compliance be improved to be totally clear.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition.		

Organization	Yes or No	Question 1 Comment
Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. The Transmission Operator may anticipate an Emergency condition without having a declared Emergency. No change made. R2: This language was deleted. **R2**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.		
MRO's NERC Standards Review Forum	No	We disagree with the statement in R8 ". . . have been identified by the Transmission Operator as supporting its internal area reliability . . .". This statement puts an SOL on the same level as an IROL, which is not the intent of an SOL. The Transmission Operator should inform the Reliability Coordinator of IROL's that may impact the reliability of the BES, but not SOL's. R9 - We continue to believe that SOL's should not be a part of the TOP-001-2 standard. There are not identified timeframes in the NERC standards that apply to SOL's. There has been no basis for the 30 minute timeframe listed, as "generally accepted by the industry" is not a technical basis, and SOL's are often tied to thermal limits and other steps can be taken locally to offset the SOL. If SOL's must be included, a better subset must be defined excluding thermal limits with any time limits being clearly specified as a return time after the SOL limit was exceeded. An example definition might be "non-thermal SOL's are those facilities limited below their maximum thermal capability as a proxy to maintain BES stability."Including SOL's in R11 effectively makes them equivalent to IROL's for mitigation purposes. Consistent with our comments in R8 and R9, SOL's must either be removed from consideration, or more narrowly defined to the appropriate set of SOL's that directly impact the reliability of the BES (cause instability, uncontrolled separation, or cascading outages). The SDT should ensure that TOP-001 consistent with FAC-014-2 R2 concerning identification of SOLs.
Response: R8: The SDT agrees the subset of SOLs identified are treated the same as IROLs because they have been identified by the Transmission Operator itself as needing special treatment. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. No change made. Requirements R9 and R11 were modified to address other comments related to the 30 minute limit. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous		

Organization	Yes or No	Question 1 Comment
duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.		
FirstEnergy	No	We have the following comments and suggestions:1. R3 - Since this requirement is describing actions to be taken in Real-time as shown in the Time Horizon, the use of the term "Operational Planning Analysis" may not be appropriate. This is because an analysis in the operations planning timeframe is restricted to next day and up to 12 months in the future. We suggest that the team reconsider of the use of this phrase and remove the last part of this requirement, specifically remove "based on its assessment of its Operational Planning Analysis". 2. R6 - We do not agree with the phrase "and negatively impacted interconnected NERC registered entities". We believe that it should be the responsibility of the Reliability Coordinator to notify all impacted entities since they are afforded the wide-area view of the area. 3. R6 - The phrase "control equipment" is too broad and lacking clarity with regard to the phrase "between the affected entities". We suggest that additional clarification be added by providing examples of the types of control equipment or the loss of functionality that could occur due to the outage.
Response: Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. **R3**. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]* **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]* R6: The SDT does not agree that Transmission Operators should not coordinate with neighboring Transmission Operators. The phrase 'negatively impacted interconnected NERC registered entities' was arrived at over multiple postings with industry – no change made. However, other changes were made in Requirement R6 to help with clarity.		

Organization	Yes or No	Question 1 Comment
R6. Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.		
East Kentucky Power Coop. Southwest Transmission Cooperative, Inc.	Ballot Comment	We thank the standards drafting team for their efforts in drafting this set of standards and believe they are significantly improved over the existing standards. We have identified some issues that warrant additional consideration by the drafting team. While TOP-001-2 R8 is an improvement of the existing TOP-004-2 R1, it introduces new ambiguity into the standards. What criteria should the TOP use for identifying the subset of non-IROL SOLs? If the TOP has a procedure/process document that defines how it identifies these SOLs and follows that procedure/process, will it be compliant with the requirement? Can the TOP ever be second-guessed on its list? The clause “that represents projected System conditions” is redundant with the definition of Operational Planning Analysis in TOP-002-3 R1. To avoid confusion, TOP-002-3 R2 should reference that the SOLs are those identified in TOP-001-2 R8 similar to how TOP-001-2 R11 references it.
Response: This requirement does not require the Transmission Operator to find SOLs that support its internal area reliability. It only requires that any of those that are identified must be communicated with the Reliability Coordinator. The SDT recognizes that Transmission Operators face different system challenges; some, serving ozone non-attainment major metropolitan areas, may be subject to other conditions that require a heightened level of monitoring and care. The phrase ‘internal area reliability’ was left undefined to encompass each of these unique challenges. The SDT believes the Transmission Operator cannot be second-guessed on this list. No change made. The SDT considered deletion of this phrase; however, it provides clarity for this requirement and does not introduce ambiguities. No change made. The SDT agrees and has made conforming changes to TOP-002-3, Requirement R2.		
LG&E and KU Energy PPL Supply	No	While LG&E and KU Energy generally agrees with the changes that were made, we do not feel the standard is ready for balloting based on the following comments:R1 and R2 - In both requirements, notification of the TOP is required and appears to be for the same condition. If this is not so, the requirements need to be more specific regarding the reasons for notification. For example, R1 appears to require notification for specific conditions regarding violations of

Organization	Yes or No	Question 1 Comment
		safety, equipment, regulatory or statutory requirements and R2 could be interpreted that after agreeing to and during the course of complying with a reliability directive, the entity was unable to do so. LG&E and KU Energy does not believe that these two requirements need to be separated.Moreover, to the extent there are duplicative requirements for the same issue, if a violation were to occur, an entity may be in violation of two requirements instead of one. The standards must clearly state what is required and must do so without creating duplicative or overlapping requirements or sub-requirements. As presently drafted, R1 and R2 create confusion as to what is required and could result in multiple self reports for the same potential violation and potentially additional penalties as a result of two violations for what appears to be the same issue. R3 - This requirement appears to be an operational planning requirement and may more appropriately be inserted in TOP-002-3. If it remains in this standard, we suggest the following wording: Each TOP shall inform its RC and all other TOPs that are expected to be affected by anticipated emergencies based on its operational planning analysis. LG&E and KU Energy thinks “assessment” is synonymous with “analysis”). We also believe that R5 is intended to cover real-time operations. The time horizons do not appear to match the requirement, i.e., Operations Planning. R4 - No comments R5 - LG&E and KU Energy recommend similar language to that in R3 for consistency and clarity, i.e., R3 has “all other transmission operators” and R5 has “other Transmission Operators”. The requirement is unclear in describing who is responsible for informing whom, needs to be rewritten to clarify. R6 - What is meant by “associated communication channels”? Data or Voice or both? Is this not covered by the COM Standards? Additionally, please clarify what is intended by terms “negatively impacted interconnected NERC entities” and “control equipment” as used in proposed R6. R7 - No comments R8 - The use of Operational Planning Analysis in this requirement is not consistent with the Time Horizon of Real-time Operations. Based on the NERC definition Operational Planning Analysis is considered future looking (next-day through 12 months) this would exclude modification to SOLs made during Real-time Operations.SOLs utilized in Operational Planning Analysis are based on certain assumptions given forecasted conditions or historical data. Real-time operating conditions can vary drastically from these assumptions and there

Organization	Yes or No	Question 1 Comment
		needs to be flexibility in modifying SOLs to account for these actual system conditions. R9 - The 30 minute duration is quite restrictive in resolving an SOL exceedance, especially for those that are considered to support internal area reliability. Does this apply only to actual SOL exceedances, or does it also include post-contingent SOL exceedances? LG&E and KU Energy feel the time limit should be at least 90 minutes for exceeding an SOL (especially for post-contingent SOLs), to allow for use of TLR procedures or other measures which often take more than 30 minutes to implement.There needs to be some flexibility in establishing Real-time Operations SOLs based on actual system conditions separate from the Operational Planning Analysis. R10 - Because the Time Horizon is "Real-time Operations" the SOLs communicated to the RC per this requirement should be the Real-time Operations established SOLs, not the Operational Planning Analysis SOLs established in R8. R11 - The SOLs established in R8 deal with future looking Operational Planning Analysis, however this requirement deals with Real-time Operations. Need clarification about Real-time Operations SOLs and we suggest the time duration for SOLs exceedances should be at least 90 minutes as described in R9.

Response: The SDT agrees and has made changes to the requirements to address your concerns.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. Language has been changed to make Requirement R3 consistent with Requirement R5.

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or

Organization	Yes or No	Question 1 Comment
expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]* R6: The COM standards cover voice only. The terminology used in Requirement R6 is well understood. No change made for this comment. The phrase 'negatively impacted interconnected NERC registered entities' was arrived at over multiple postings with industry – no change made. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R10 – For SOLs discovered in real-time, the Transmission Operator doesn't need to inform as it is an SOL and hasn't been previously reported to the Reliability Coordinator. No change made. R9 and R11: Agreed and language changed to reflect the intent of the suggested changes. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v.}$, or of an SOL identified in Requirement R8.		
SERC OC Standards Review Group	No	While we generally agree with the changes that were made, we do not feel the standard is ready for balloting based on the following comments:R1 and R2 - In both requirements, notification of the TOP is required and appears to be for the same condition. If this is not so, the requirements need to be more specific regarding the reasons for notification. For example, R1 appears to require notification for specific conditions regarding violations of safety, equipment, regulatory or statutory requirements and R2 could be interpreted that after agreeing to and during the course of complying with a reliability directive, the entity was unable to do so. The group does not feel that these two requirements need to be separated. R3 - This requirement appears to be an operational planning requirement and may more appropriately be inserted in TOP-002-3. If it remains in this standard, we suggest the following wording: Each TOP shall inform its RC and all other TOPs that are expected to be affected by anticipated emergencies based on its operational planning analysis. (We think "assessment" is synonymous with "analysis"). We also believe that R5 is intended to cover real-time operations. The time horizons do not appear to match the requirement, i.e., Operations Planning.

Organization	Yes or No	Question 1 Comment
		R4 - No comments R5 - We recommend similar language to that in R3 for consistency and clarity, i.e., R3 has “all other transmission operators” and R5 has “other Transmission Operators”. R6 - What is meant by “associated communication channels”? Data or Voice or both? Is this not covered by the COM Standards? R7 - No comments R8 - The use of Operational Planning Analysis in this requirement is not consistent with the Time Horizon of Real-time Operations. R9 - We feel the time limit should be 90 minutes for exceeding an SOL, to allow for use of TLR procedures or other measures. R10 and R11 - Logically these two requirements should be swapped so that the requirement to act is performed prior to notification of actions taken. The reference to 30 minutes should be changed to 90 minutes (see comment to R9 above).

Response: The SDT agrees and has made changes to the requirements to address your concerns.

R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.

R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.

Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this. Language has been changed to make Requirement R3 consistent with Requirement R5.

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*

Organization	Yes or No	Question 1 Comment
R6: The COM standards cover voice only. The terminology used in Requirement R6 is well understood. No change made for this comment. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R9 and R11: Agreed – the 30 minute time limit was deleted. **R9**. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. **R11**. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_{v}., or of an SOL identified in Requirement R8. R10 – The requirements are not sequential. No change made.		
Progress Energy	No	
Response: Without specific comments, the SDT is unable to respond.		
Florida Municipal Power Agency	No	R5 requires communications / coordination more than the version 1 standard (old R7) to those actions that can result in an Adverse Reliability Impact, which are very few and is ambiguous. FMPA suggests adding the phrase "or cause an SOL or IROL to be exceeded" to the requirements, such as "Each Transmission Operator shall inform neighboring other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact or cause an SOL or IROL to be exceeded on those respective Transmission Operator Areas ...." Also, there seems to be overlap of responsibility with the RC in real-time operations concerning SOLs and IROLs. FMPA can certainly see informing the RC and neighboring TOPs of a potential SOL / IROL in an Operational Planning Assessment, but, in real-time, that may be too much of a burden and might step on the RC's toes in efficient and effective communication and coordination. R7 is ambiguous as to whether the IROL and IROL Tv are IROLs identified in real-time or identified through Operational Planning Analysis. R7 should be treated in a similar manner to R9 and refer to those IROLs identified through the Operational Planning Analysis. The concern is that if an extreme contingency occurs beyond what is in the scope of the Operational Planning Analysis, and that extreme contingency causes an IROL with a very short Tv in real-time, will the TOP be able to comply?

Organization	Yes or No	Question 1 Comment
		R8 belongs in TOP-002-3 since it is Operational Planning Analysis. R11 seems to create double jeopardy with R7 and R9. R11 should be deleted and the concepts embedded in R11, such as "direct others" and "limit the magnitude and duration", ought to be included in R7 and R9 instead.
Response: R5 – The language of Requirement R5 was changed due to comments from others and it now provides better clarity as to the SDT's intent. **R5.** Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. The SDT does not see an overlap. The Transmission Operator is responsible for all SOLs and for informing the Reliability Coordinator of the subset of SOLs that will receive greater scrutiny. No change made. R7: An IROL that emerges in real-time may not have been identified in the Operational Planning Analysis. If you don't know about it, you can't control it and wouldn't be responsible. Requirement R8 covers those IROLs that can be anticipated. No change made. R8: The act of informing the Reliability Coordinator is real-time; the requirement was left in TOP-001-2. No change made. R11: This requirement does not create double jeopardy. Requirement R11 is mandating that you take action to avoid a violation of Requirements R7 and R9. No change made.		
Manitoba Hydro	Yes	The term 'reliability entity' used in TOP-001-02 should be changed to 'registered entity'.
Response: The SDT reviewed TOP-001-2 and could not locate any instances of "reliability entity" to change. "Registered entities" was used in Requirement R6.		
Northeast Utilities	Yes	Suggest rearranging R4 to read: Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment, regulatory, or statutory requirements, and provided that the requesting entity has implemented its comparable emergency procedures.
Response: The SDT considered this suggestion but did not accept it. This change does not add clarity. No change made.		
Pepco Holdings Inc	Yes	Should the standard be applicable to a TO? Specially it would appear that R1 and R2 should be applicable to a TO in addition to the other listed entities.

Organization	Yes or No	Question 1 Comment
Response: All transmission facilities must have a Transmission Operator. This applies to operators not owners.		
BGE	Yes	Comment on proposed TOP-001-2 Reliability Directive definition: Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency.This needs to also include: The RC, TOP or BA must clearly state that "This is a Reliability Directive".
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. This comment has been forwarded to that SDT for consideration. However, the SDT agrees with the definition as presently crafted. No change made.		
City of Tacoma or Tacoma Public Utilities	Yes	1. The Standard Development Roadmap, page 2, states there are no new or revised definitions yet there is a revised definition for "Reliability Directive." Reliability Directive is not listed in NERC's Glossary of Terms. 2. The terms "Operational Planning", "Same Day Operations" and Real-time Operations" need definitions that include a time horizon. 3. R1: The language is redundant with R2. Removing "...the respective entity informs its Transmission Operator that..." from R1 would eliminate the redundancy. 4. R5: New R5 language replaces the old language from TOP-001-2 R 7.3.Proposed: "Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, transmission or load."Existing R7, R.3:"When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generation Operator shall notify the Transmission Operator and the Transmission Operator shall notify its Reliability Coordinator and adjacent Balancing Authority, at the earliest possible time."Suggestion - Include language to identify the time requirement for communications including after-the-fact notifications. The purpose of the requirement is to inform, yet there is no associated timeframe. 1. R10: Similar to R5, this requirement also needs an associated timeframe to

Organization	Yes or No	Question 1 Comment
		inform the RC, otherwise it's difficult to measure.
Response: The definition of Reliability Directive is not under the control of this SDT. The RCSDT (Project 2006-06) developed that definition. Their standards have been through one ballot and will be posted again for ballot soon. It is shown here for the reviewer's convenience. No change made. Time Horizons are defined at NERC: http://www.nerc.com/files/Time_Horizons.pdf R1: Agreed and conforming changes were made. **R1**. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. R5 & R10: There is no definable timeframe for all conditions consistently and objectively measurable. No change made.		
BC Hydro	Yes	
Bonneville Power Administration	Yes	
Luminant Energy	Yes	
Western Electricity Coordinating Council	Yes	
Luminant Power	Yes	
Indeck Energy Services	Yes	
ReliabilityFirst	Yes	
Puget Sound Energy	Yes	
Georgia Transmission Corporation	Yes	
Response: Thank you for your support.		

2. **The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The SDT made a few minor clarifying changes in response to comments received. The SDT does not consider the changes to be substantive.

The SDT revised Requirement R2 of TOP-002-3 to read as a positive statement rather than as a double negative. The change is simply a restatement without changing the meaning of the requirement, but should be clearer now.

A few commenters were concerned with the use of what they believed to be a definition that is not included in the Glossary of Terms used in NERC Reliability Standards. The definition of concern is that of Operational Planning Analysis. The definition is in the glossary, so the SDT doesn't understand the comments and no change was made.

The SDT made a clarifying change to Requirement R3 of TOP-002-3 by adding the term "NERC" as a modifier of "registered entities".

The SDT made revisions in TOP-001-2 to clarify the time relating to the exceedance of the subset of SOLs that, while not IROLs, has been identified by the Transmission Operator as supporting its internal area reliability. Concerns were expressed that 30 minutes was not applicable to all SOLs. The SDT agrees and has made the clarifying changes.

Some commenters were concerned with the notifications indicated in Requirement R3 for entities identified in an operating plan. Some of the commenters said it could be read to mean all entities have to be notified. The SDT reviewed the comments and the wording and did not agree that the language needed to be changed. The standard describes "what" must be done;
namely, review and plan how to address predicted exceedances, but does not specify "how" to do the plan, which would be unnecessarily prescriptive. When the Transmission Operator performs its planning activities, those entities identified as having a role in the mitigating actions are identified. It is only those entities that will have a role in the execution of the plan that must be notified.

R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their

role in those plan(s).

Organization	Yes or No	Question 2 Comment
City of Tacoma or Tacoma Public Utilities	No	R2: "Each Transmission Operator shall plan to preclude operating in excess of Interconnected reliability Limits (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified as supporting its internal area reliability, as a result of the Operational Planning Analysis performed in Requirement R1."Suggestion - The statement in red is a double negative and difficult to follow. Rewrite this sentence to be a positive statement to avoid confusion, for example, "Each Transmission operator shall plan to operate within identified ..."
Response: The SDT agrees and has revised Requirement R2. **R2.** Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Duke Energy Duke Energy Carolina	No	This standard uses the capitalized term "Operational Planning Analysis" which is not currently a NERC defined term. How is this to be applied in the standard? o R2 - We reiterate our comments on TOP-001-2 regarding the problematic phrase "supporting its internal area reliability". Will an entity's Operational Planning Analysis be found deficient if no SOLs have been identified which support "internal area reliability"? We believe that it is certainly possible. Furthermore, in M2, what evidence will be required to be presented to demonstrate that an entity has no SOLs which "support internal area reliability"? o R3 - insert the word "NERC" before the word "registered" to add clarity.
Response: The term "Operational Planning Analysis" is in the Glossary of Terms used in NERC Reliability Standards. No change made. The SDT reminds you the Transmission Operator has primary responsibility for all System Operating Limits (SOLs) within its purview (or footprint or area). The requirement is for the Transmission Operator to decide which of its SOLs rise to a greater degree of importance to its internal area reliability such that the Transmission Operator wishes the Reliability Coordinator to join in monitoring and controlling system parameters within the SOL(s). If the Transmission Operator does not believe it has any such SOLs, it is not required to notify the Reliability Coordinator of any. No change made.		

Organization	Yes or No	Question 2 Comment
The SDT has added the word "NERC" to provide clarification. **R3**. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).		
Ameren	No	(1)R1 refers to "Operational Planning Analysis" which is not a defined term. Similarly, R3 uses the phrase "registered entities identified in the plan(s) cited in R2 which is confusing. Please define/clarify these terms or phrases. (2) In R2 (similar to R8 in TOP-001-2) , what is meant by "internal" area reliability? We have a significant concern form a compliance perspective about how would it be interpreted and audited.
Response: The term "Operational Planning Analysis" is in the Glossary of Terms used in NERC Reliability Standards. No change made. The SDT reviewed the questioned language and, after discussion, does not understand what is causing the confusion. No change made. The SDT changed "local area" to "internal area" based upon comments received from the industry. While all SOLs are relevant for only localized issues, not widespread BES issues, each Transmission Operator has a Transmission Operator area within which it has primary reliability responsibilities. The SDT believes that area is its "internal area" and does not involve crossing boundaries or affecting other Transmission Operator area(s). No change made.		
MRO's NERC Standards Review Forum	No	believes that the boundaries are not identified in TOP-002-3 R2. For IROLs, the boundaries should be limited to the Registered Entities footprint.
Response: The SDT disagrees. IROLs definitely may involve crossing boundaries between registered entities' footprints. Operations within one area may affect system flows or other parameters within other areas, or the limits may be on interconnecting facilities. Typically the Transmission Operator has the most granular and specific information for the system facilities within its area, but the Reliability Coordinator has a widespread view, albeit that it may be at a higher level and less granular. The plans of the Transmission Operator that are relevant to Requirement R2 are those plans the Transmission Operator will implement to ensure operating actions within the IROLs and SOLs. The Transmission Operator is also required to notify other entities which will have a role in the execution of those plans. Therefore, there are many different potential combinations of areas and boundaries and possible interconnecting facilities between areas that may be involved in such operating action plans. No change made.		
Electric Market Policy	No	Dominion is unsure as to which version (clean or redline) of the language in the grey box (for R1) the SDT intended. The sentence (in red line version) appears to read "Rationale for Requirement R1: Operational Planning Analysis (OPA) does not the analysis even if those

Organization	Yes or No	Question 2 Comment
		tools are not available." Please clarify. We also did not find any changes to the Data Retention (red line version).
Response: The clean version is the correct version.		
City of Green Cove Springs Florida Municipal Power Agency	Ballot Comment	GCS still believes that unit commitment needs to be covered better when moving from the old TOP standards to the new TOP standards. Yes, unit commitment is a BA function, not a TOP function, and yes, BAL-002 does cover a portion of unit commitment, e.g., making sure there are adequate contingency reserves, but, I can't find where there is a requirement in the BAL standards for unit commitment to cover the peak load of the current day / next day plus contingency reserves plus frequency reserves plus regulation reserves. BAL-002 doesn't seem to cover all of this and seems to allow load shedding to cerate room for contingency reserves. So, we are suggesting a comment to develop a temporary requirement in TOP-002-3 until the new BAL standards, presently under development, include this (and I'm told that the present standard development effort does). GCS is proposing that this temporary requirement would be retired with the new BAL standard. GCS suggests that TOP-002-3 include a temporary requirement for BA's to validate unit commitment that meets the current day / next day projected peak loads plus reserve requirements until it is included in the BAL standards and at which time the requirement in the TOP standards could be retired. Operational Planning Analysis is ambiguous. R1 doesn't talk about the time frame of operations planning. The old version clearly had current day, next day and seasonal operations planning requirements that probably ought to be retained, as opposed to the ambiguous phrasing of R1. It also does not talk about what is being studied, e.g., the same contingencies included in the RC SOL methodology of FAC-011 for instance. GCS suggests defining the capitalized term of Operational Planning Analysis and add it to the NERC Glossary, especially since it is a capitalized term in the standard. R2 is confusing. We are sure the intent is that, if the Operational Planning Analysis results show that an SOL or IROL would be exceeded as a result of single / double contingencies covered by the RC's SOL Methodology of FAC-011, then the TOP must develop a plan to resolve the situation within the Tv of the SOL or IROL. GCS recommends that the SDT redraft R2 to make it less confusing and add clarity, maybe something like: "Each TOP shall develop plans to relieve an SOL or IROL violation identified in the results of Operational Planning Analyses within the time constraints related to the SOL or IROL (e.g., within the time frame of emergency ratings or the IROL Tv)" Such a change will also help clarify which entities are notified in R3. Currently, R3 is ambiguous as well since R2 as currently drafted seems to indicate that the Operational

Organization	Yes or No	Question 2 Comment
		Planning Analysis itself if the plan, and since everyone has a role in that plan, then R3 seems to indicate that everyone needs to be notified, which we doubt is the intent of the SDT.
Response: Regarding the removal of the Balancing Authority: The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2. The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis. The timeframe of the Operational Planning Analysis is part of the definition. No change made. The term "Operational Planning Analysis" is in the Glossary of Terms used in NERC Reliability Standards. No change made. TOP-001-2 has been revised to more clearly address the time relating to the exceedance of the subset of SOLs that is included in the limits that the Transmission Operator has informed the Reliability Coordinator to be important to the Transmission Operator's internal area. The SDT did not intend that everyone would have a role in the plan. The Transmission Operator would identify the entities that would have responsibility for the facilities that would be involved in the execution of the operating plan. Those are the only entities that must be notified, not all entities. No change made.		
Nebraska Public Power District	No	NPPD does agree in general with the intent of the proposals under this ballot, however there is change needed in TOP-002-3. The language in TOP-002-3 R2 is not clear and could be interpreted to require an entity to include all IROL's in the interconnection, which is way too broad. NPPD suggests that R2 of TOP-002-3 be reworded to be clear that the requirement is addressing IROL's and SOL's "within the Transmission Operator's Area".
Response: The Reliability Coordinator and the Transmission Operator must work in coordination and close communication. The Reliability Coordinator is expected to discuss with the Transmission Operator those areas and facilities within its area that are involved with, or can impact, IROLs and, possibly some of the SOLs that the Transmission Operator or other Transmission Operators have identified as affecting their internal area reliability. To be sure, there are IROLs and SOLs in the Bulk Electric System (BES) that any given registered entity may not be able to affect,		

Organization	Yes or No	Question 2 Comment
either positively or negatively. However, each IROL is the responsibility of a Transmission Operator. The Transmission Operator is obligated to notify those entities that have a role in its plan to resolve the IROL. No change made.		
SERC OC Standards Review Group LG&E and KU Energy PPL Supply	No	R1 - No comments R2 - The word "preclude" can be interpreted as "prevent", which would mean that any exceedance of an IROL or SOL would be a violation, regardless of duration. Other wording, such as "avoid" should be considered. R3 - No comments
Response: The SDT has revised the wording of Requirement R2 in response to comments. **R2.** Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Southern Company	No	R1 -It is still unclear to us if Operations Planning Analysis includes Contingency analysis as the NERC Glossary does not explicitly state. Edits to the rationale box were such that we could not understand the intent. R3-Is the standard expecting a comprehensive written plan as a result of the planning that takes place in R2? Is the intent of this requirement to notify all registered entities that may be affected by a mitigation plan for the next day?Example: An SOL is identified in the Operational Analysis for the next day from R2. The plan to mitigate this SOL is to call an IDC-TLR. The level of the TLR may or may not reach level 5. If the TLR reaches level 5 many generators will be required to be re-dispatched inside and outside of the TOPs area. This requirement will require the transmission operator to notify every Generator Operator that could possibly be re-dispatched for a TLR-5. It would be preferable to use the term "reliability entities" or at least replace the generic term "registered entities" with a listing of the Functional Model Entities that need to be notified. The use of registered entities would require reliability information to be given to marketing entities.
Response: The SDT has corrected an editing problem related to Requirement R1 and the text box. Requirement R2 doesn't mandate a written plan, but Measure M2 points to plans and processes. Typically plans in written form are easier to use to present evidence that a plan exists. Measure M2, therefore, recognizes written plan(s) as one option. Requirement R2 requires the Transmission Operator to plan. Without being so prescriptive as to tell "how" to do this, the SDT believes that the		

Organization	Yes or No	Question 2 Comment
Transmission Operator, in conducting its planning, will identify potential problem areas and what actions may be required to address those areas. The Transmission Operator must identify other entities which will have a role in executing any operating action plans that will be required to resolve issues as they arise. The SDT recognizes there are many different organizational structures and contractual arrangements in various areas of the BES. Each registered entity knows the arrangements that are in place for its facilities; for instance, generators are typically re-dispatched through Balancing Authorities and Generator Operators. It is not possible to specifically state each procedural action that must occur for this to take place. If the Transmission Operator typically calls the Balancing Authority, then the Balancing Authority knows how to implement the required actions. No change made. The SDT has added the word "NERC" to provide clarity to the requirement. **R3**. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).		
Wisconsin Electric Power Company	No	R3 the TOP should provide the plan to its RC and BA (s) in addition to notifying other entities of expected actions. The use of the phrase "all registered entities" is too open ended, and not limited to operational functions as it should be. In addition some actions may be required of entities not registered.
ITC	No	Regarding R3: Consistent with our comments on TOP-001 R6, we believe that the use of the word "registered" entities does not provide value, and only adds an unnecessary administrative step to operating personnel. We recommend just using "entities".
Response: The SDT has added the word "NERC" to provide clarity to the requirement. **R3**. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).		
City of Vero Beach	Ballot Comment	The City of Vero Beach still believes that unit commitment needs to be covered better when moving from the old TOP standards to the new TOP standards. Yes, unit commitment is a BA function, not a TOP function, and yes, BAL-002 does cover a portion of unit commitment, e.g., making sure there are adequate contingency reserves, but, I can't find where there is a requirement in the BAL standards for unit commitment to cover the peak load of the current day/next day plus contingency reserves plus frequency reserves plus regulation reserves. BAL-002 doesn't seem to cover all of this and seems to allow load shedding to cerate room for contingency reserves. So, we are suggesting a comment to develop a temporary requirement in TOP-002-3 until the new BAL standards, presently under development, include this (and I'm told that the present standard development effort does). The City of Vero Beach is proposing that this temporary requirement would be retired with the new BAL standard.

Organization	Yes or No	Question 2 Comment
Lakeland Electric	Ballot Comment	The new standard is just the TOP, which is appropriate; the old TOP-002-1 basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed(interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). BAs are eliminated from the new version 2 standard, and with no similar requirement in the BAL standards, FERC will likely see a reliability gap, no entity is ensuring that enough generation is being committed to serve current day / next day peak loads, e.g., no entity seems to be responsible for validating unit commitment.
Lakeland Electric	No	TOP-002-3: Operations Planning The prior version 2 standard was applicable to both the BA and the TOP. The new standard is just the TOP, which is appropriate; however, it was the old TOP-002-1 that basically required the BA to validate the unit commitment of resources to ensure enough capacity is committed (at least that's how I interpreted R5, R6 and R7 of the version 2 standard and how they would apply to a BA). Since BAs are eliminated from the new version 2 standard, and since there is no similar requirement in the BAL standards that I am aware of, FERC will likely see a reliability gap that no entity is ensuring that enough generation is being committed to serve current day / next day peak loads, e.g., no entity seems to be responsible for validating unit commitment. The SDT claims that BAL-001-1 covers the operations planning perspective of a BA, but, BAL-001-1 covers unit commitment only loosely on an annual or monthly basis. The new version also doesn't talk about the time frame of operations planning. The old version clearly had current day, next day and seasonal operations planning requirements that probably ought to be retained, as opposed to the ambiguous phrasing of R1.

Response: Regarding the removal of the Balancing Authority from Requirements R5, R6, and R7:

The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be ‘in charge’. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority.

The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2.

The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2.

Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.

Organization	Yes or No	Question 2 Comment
Progress Energy	No	TOP-002-3 R2...Our initial concern was that an auditor could read this requirement as requiring a specific plan to address each IROL and SOL. This interpretation does not make much sense, but it is supported by the wording of the measure, which says, "Such evidence could include but it is not limited to plans, processes, or procedures for precluding operating in excess of each IROL and each SOL." We can picture an auditor going down a complete list of IROLs and SOLs and asking, where is your plan for A, where is your plan for B, etc.The standard should not require the Transmission Operator to prepare a plan to address IROLs and SOLs unless the Operational Planning Analysis indicates the potential for a thermal or voltage problem for that element due to normal (N-0), contingency (N-1), or sensitivity analysis result. So, the logical way to read this requirement is to say that the completion of the Operational Planning Analysis is the "plan", and if there are no IROL/SOL limits exceeded, then you have met the requirement. If this is what the SDT meant, then the wording of the requirement should be revised and clarified. Also, We are concerned about the requirement to "...plan to preclude operating in excess...", because "preclude" is defined to mean "make impossible" or "take action in advance to make impossible". Precluding these events is inconsistent with the time limits established in the new TOP-001-3 standard. This could be read to require pre-contingency action for any contingency involving an IROL/SOL, which could cause major operational problems to say the least. All of the prior standards, including the TOP, TPL, and the Rules of Procedure governing the seasonal assessment process provide latitude in how studies are performed, and what pre- and post- contingency actions are taken. This standard should be clarified to provide comparable latitude in addressing IROL and SOL issues. Just changing "preclude" to "mitigate" would be a good start.... Also, requirement R2 is unacceptably vague in that it requires plans for SOLs that "support internal area reliability" without indicating how those SOLs are identified or selected as a subset of all SOLs. Also, R8 of TOP-001-3 requires that the RC be notified of the existence of these SOLs, whatever they are....

Response: The SDT believes that Operational Planning Analysis (OPA) will identify areas that need specific attention and specific plans. A Transmission Operator may have a standing practice of constraint management which will address the great majority of IROL or SOL requirements. In such a case, evidence of the existence of such a practice and evidence that the practice was followed will address the requirement. For those issues identified in the OPA as needing specific operating action plans, the Transmission Operator can show how each is covered in its procedures or, when required, in case-specific plans. Such plans may be standing or temporary, depending upon the system conditions involved. The standards are not prescriptive as to "how" the entity is to address the issues, just what the entity is required to do. No change made.

The SDT has revised the wording of Requirement R2.

Organization	Yes or No	Question 2 Comment
R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. The SDT changed "local area" to "internal area" based upon comments received from the industry. While all SOLs are relevant for only localized issues, not widespread BES issues, each Transmission Operator has a Transmission Operator area within which it has primary reliability responsibilities. The SDT reminds you that the methodology for developing SOLs, as required by the FAC standards, requires that all SOLs respect the Facility Ratings used in the development of the SOLs. No change made.		
Colorado Springs Utilities	Yes	Colorado Springs Utilities respects the difficulty in crafting language which satisfies all potential interpretations of a requirement. We do, however, suggest changing "planning to preclude operating" under R2 to "plan to operate", giving you the following: "Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator via the Operational Planning Analysis performed in Requirement R1 as supporting its internal area reliability."Perhaps the definition of SOL should be revised to include the principle of "internal area reliability". Then, everything not IROL or SOL could go back to being facility ratings or the like.
Response: The SDT has revised the wording of Requirement R2. **R2.** Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. The SDT changed "local area" to "internal area" based upon comments received from the industry. While all SOLs are relevant for only localized issues, not widespread BES issues, each Transmission Operator has a Transmission Operator area within which it has primary reliability responsibilities. The SDT reminds you that the methodology for developing SOLs, as required by the FAC standards, requires that all SOLs respect the Facility Ratings used in the development of the SOLs. No change made.		
Yes		
Yes		
Yes		

Organization	Yes or No	Question 2 Comment
Yes		
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Organization	Yes or No	Question 2 Comment
Yes		
Yes		
Yes		
Response: Thank you for your support.		

3. **The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The majority of the comments were asking for clarification. The SDT made specific changes to Requirements R2 & R3 to spell out that the intent of the SDT is to allow the Transmission Operator and Balancing Authority to request any data they need to perform their monitoring and operations planning functions as long as the entity has a reliability-based need for that data. The SDT also deleted the two sub-bullets in Requirement R1 in this same vein.

R2. Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements.

R3. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements .

Organization	Yes or No	Question 3 Comment
City of Tacoma or Tacoma Public Utilities	No	1. In general, the standard language as written is vague. 2. R1: Though a minimum list of required data may be construed as too prescriptive and may "stifle creativity and innovations," the absence of a pre-defined list will promote inconsistencies between entities and may risk an Auditor interpreting what data is needed for an "Operational Planning Analysis" differently from the utility. 3. R1.1: The term "long term outages" needs a definition. How long is "long term?" 4. R1.1: The term "operating parameters" also need a definition.

Response:

1. Without a specific comment, the SDT is unable to respond. No change made.
2. The noted audit concern can never be eliminated based on the reality that auditors may incorrectly cite an audited entity for actions or items not required by the standard. Requirement R1 is actually quite specific – the data specification limits the data to be provided as only that data explicitly requested by a Transmission Operator or a Balancing Authority. If the data is not on the list, than the data need not be supplied regardless of what an auditor considers as necessary. A given auditor may find the entity non-compliant but that non-compliance should be

Organization	Yes or No	Question 3 Comment
overruled based on the requirement as written. No change made. **3.** (and 4.) The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
MRO's NERC Standards Review Forum	No	As currently written, R1.1 could be interpreted to include all of the distribution facilities of a Registered Entity. It needs to be revised to include only the lower voltage facilities proven to impact the reliability of the BES. In R1.1, please clarify "long-term" as the term applies to outage of BES Facilities. What length of time must pass before an outage I is considered "long-term"? In R1.1, clarify "Operating Parameters" as the term applies to BES Facilities and those Facilities at voltages lower than the BES. We recommend that a list of required parameters be included within the Requirement. Recommend rewording R2 (and R3) as follows: "Each Transmission Operator shall distribute its data specification document to all NERC Registered Entities that provide Facility status to the Transmission Operator."
Response: The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted. The technical issue raised by the commenter will not be resolved by the proposed rewording. The proposed rewording is to have the requesting entity send documentation to those that already provide data. The proposed rewording begs the question of what to do with new entities, or entities that have changed Transmission Operators. However, the SDT has made clarifying changes to the wording of both requirements. **R2**. Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements . As newly worded, this requirement limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis.		
Cowlitz County PUD	No	Cowlitz has no disagreement with any of the changes made; however Cowlitz struggles why the Load-Serving Entities (LSEs) are included in the Applicability section. From requirements R2 and R3 it is clear that Facility monitoring and status is involved. From the Reliability

Organization	Yes or No	Question 3 Comment
		Functional Model it is clear that LSEs do not own Facilities, but rather are more ambassadors between the End-use Customers and registered entities that do own facilities. Although the Statement of Compliance Registry Criteria implies that the LSEs might own UVLS and/or UFLS equipment, the Reliability Functional Model is clear that the LSE only helps identify those critical customer loads that should be excluded in such load shedding programs. Therefore, Cowlitz urges the SDT to remove the LSEs from the Applicability section. Cowlitz also suggests that Distribution Providers be included in the Applicability section as these entities do own Facilities that may require monitoring and status by the TOP and BA.
Response: Load-Serving Entity's have load data that is necessary to conduct an Operational Analysis. While a Load-Serving Entity may be by default required to provide such information, that does not mean that every Load-Serving Entity will be asked to provide such information (as some reliability entities provide their own composite forecast loads and do not need each Load-Serving Entity's forecast.) No change made. There are no other comments that there is any data needed by the Transmission Operator or Balancing Authority that must be supplied by the Distribution Provider. No change made.		
Illinois Municipal Electric Agency	Ballot Comment	Illinois Municipal Electric Agency (IMEA) appreciates the SDT's efforts on this initiative to simplify and improve this set of Reliability Standards. We are supportive of those Requirements which apply to the DP, LSE, and TO functions; however, IMEA is voting Negative to support concerns which have been expressed to remove the following language from TOP-003-2, R1.1: "and Facilities at voltage levels lower than the BES."
FirstEnergy	No	R1 - Subpart 1.1, Bullet #2 - We suggest that the team strike the phrase "and Facilities at voltage levels lower than the BES". NERC reliability standards are meant to provide an adequate level of reliability to the Bulk Electric System, and therefore non-BES requirements are beyond the scope of the standards. Furthermore, the current NERC initiative to revise the definition of BES and provide specifics around what is both included and excluded will alleviate any potential gaps in reliability of the BES.
Georgia Transmission Corporation	No	Section 215 of the FPA provides that the ERO "shall have authority to develop and enforce compliance with reliability standards for only the BPS."In Order 743A, the commission acknowledged that "Congress has specifically exempted 'facilities used in the local distribution of electric energy" from the BPS definition.R1.1 for TOP-003-2 references distribution assets which are outside the scope of NERC standards. GTC recommends removing reference to "Facilities at voltage levels lower than the BES"
Commonwealth of Massachusetts Department of	Ballot Comment	The other issue is in TOP-003-2 R1.1 which states: R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to

Organization	Yes or No	Question 3 Comment
Public Utilities		perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: o Long term outages of Bulk Electric System (BES) Facilities. o Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES. Some RSC members believe using language such as “but not limited to” and “levels lower than the BES” to be problematic and beyond the scope of what is needed and also creates potential for compliance issues.
ISO/RTO Standards Review Committee	No	The second bullet under R1, 1.1 facilities “at voltage levels lower than the BES;” we believe that these facilities are not enforceable under the NERC Standards. We believe any such references should be removed. We suggest removing this phrase from the bullet.
ISO New England Inc.	No	The second bullet under R1, 1.1 facilities “at voltage levels lower than the BES;” we believe that these facilities are not enforceable under the NERC Standards. We believe any such references should be removed. We suggest removing this phrase from the bullet.
Northeast Power Coordinating Council, Inc.	Ballot Comment	TOP-003-2 R1.1 states: R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: o Long term outages of Bulk Electric System (BES) Facilities. o Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES NPCC believes language such as “but not limited to” and “levels lower than the BES” to be problematic and beyond the scope of what is needed in the standard and also creates potential for compliance issues.
Pepco Holdings Inc	No	In R1.1 has an open ended requirement for operating parameters for non BES facilities. Should the language limit that to only those facilities that have an impact on BES facilities? If so, should long term outages of those facilities also be required?
PSEG Energy Resources & Trade LLC PSEG Fossil LLC Public Service Electric and Gas Co.	Ballot Comment	In TOP-003-2 Operational Reliability Data, the PSEG companies do not understand the need for the sub-BES voltage data reporting requirement in the second bullet of R1.1. This open-ended requirement appears to be potentially extremely burdensome to LSEs and TOs with no justified basis of its need to maintain BES reliability. If the sub-BES voltage phrase is removed from the Requirement so that it to simply states “Operating parameters for BES Facilities” The PSEG companies expect that they would change their vote to affirmative. Additionally, in TOP-003-2 R1.1, the phase “Long term outages” is interpreted to be planned

Organization	Yes or No	Question 3 Comment
		season outages not emergent issues that result in a long duration outage of a BES facility. Please clarify if this is a correct interpretation of the intent of the SDT.
Duke Energy Carolina	Ballot Comment	3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review process. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 No Comments: The second bullet under R1.1 has been changed so that now operating parameters for all facilities at voltages lower that BES are required. The phrase “at the discretion of the Transmission Operator or Balancing Authority” must be restored in this requirement. 3. TOP-003-2 Requirement 1, Part 1.1: This provides for exchange of data required to perform Operational Planning Analyses and real-time monitoring. These data include “Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES [emphasis added].” We believe the latter clause is unenforceable under the NERC standards and should therefore be removed.
Northeast Power Coordinating Council Hydro One Networks Inc. Independent Electricity System Operator	No	Referring to the second bullet under R1, Part 1.1, “...Facilities at voltage levels lower than the BES;” these facilities are not enforceable under the NERC Standards. Any such references should be removed. Editorial comment: remove M5 because there is no corresponding R5.
SERC OC Standards Review Group LG&E and KU Energy PPL Supply	Yes	R1.1 - It is our understanding that bullets should be avoided in the requirements. R2 - No comments R3 - No comments R4 - No comments
BC Hydro	No	R1.1 refers to “Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES”. In the previous Consideration of Comments, it was noted that “Facilities below 100kV may have material impact to the BES and, as such, are within the scope of the requirement ...”. BC Hydro feels that the wording in R1.1 “Facilities at voltage levels lower than the BES” is open-ended and it does not clearly reflect that these extra Facilities have been deemed as having material impact to the BES and therefore are subject to the NERC

Organization	Yes or No	Question 3 Comment
		MRS.
Roger C Zaklukiewicz	Ballot Comment	Requirement R1 needs to be modified as the following terms in 1.1 are problematic to compliance and enforcement. Remove the term "but not limited to". Why must the data to be exchanged include that on all facilities that operate at levels lower than the Bulk Electric System to ensure the reliability of the interconnected BES - especially if the BES is to be recognized as the "bright line" transmission system that operates at 100 kV or above.
Public Service Enterprise Group LLC	No	The PSEG Companies interprets “long term outages” to be planned season outages not emergent issues that result in a long duration outage of a BES facility.
United Illuminating Co.	Ballot Comment	UI Votes negative due to TOP-003 R1.1 requirement that the TOP can request operating parameters for Facilities at voltage levels lower than the BES. If a facility lower than 100 kV is required to be included in the BES then the exception process should be followed to include it in the BES. Non-BES designated facilities cannot be subject to mandatory reliability standards.
Puget Sound Energy	Yes	The second bullet in R1.1 needs clarification. As originally drafted, this was permissive language allowing entities to include non-BES information in their data specifications. However, with the revisions, this section now requires all entities to do so, whether or not such data is necessary or pertinent for their operations. As a result, the second bullet should be revised to retain its permissive character or should be removed from the standard altogether.
Response: The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
Ameren	No	In R1, 1.1 “at the discretion of the Transmission Operator or Balancing Authority” phrase should be reinstated.
Response: The SDT has made changes to requirements R2 & R3 to address this issue. As newly worded, this limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis. **R2.** Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator’s		

Organization	Yes or No	Question 3 Comment
reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements .		
Electric Market Policy	No	Is this question meant to refer to TOP-003-2? If so, then Dominion's response is that we agree, but do not see why the SDT felt it necessary to add "web postings with acknowledgement" to M2 and M3. The sentence "Such evidence could include but is not limited to ....” was sufficient without the addition. Dominion believes this language will invite others to want to add the types of evidence found usefher may grow over time.
Response: The measurement language was linked to the closed-loop nature of some forms of evidence as opposed to other forms. When request and response is directly and independently documented there is no problem. However, the use of posting is indirect. In essence there is another step needed, i.e., to tell the other person the request is posted. Without that step an entity could be held non-compliant for something it never received a request for. The measurement merely requires that for a Transmission Operator to use that form, there is an added need to "prove" the other party knows the requests exists. No change made.		
ITC	No	ITC is concerned with the removal from R1.1 of the phrase "...at the discretion of the Transmission Operator or Balancing Authority". Why was this removed? The TO and BA should have discretion of what data it needs (especially at the sub-BES level) to perform Operational Planning Analysis and Real time monitoring. Also in R1.1, please define what "long-term outages" are.
Duke Energy	No	The second bullet under R1.1 has been changed so that now operating parameters for all facilities at voltages lower that BES are required. The phrase "at the discretion of the Transmission Operator or Balancing Authority" must be restored in this requirement.
Response: The SDT made clarifying changes to Requirements R2 & R3 to address this issue. As newly worded, this requirement limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis. **R2.** Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability		

Organization	Yes or No	Question 3 Comment
monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements . The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
PJM Interconnection, L.L.C.	Ballot Comment	PJM questions the 30 minute limitation placed on SOLs that are identified by TOPs for use by the RCs (TOP-001 R9). In addition PJM does not agree with the inclusion of non-BES assets (TOP-003 R1).
Response: (see Q1 for response to 30 min question) The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		
Florida Municipal Power Agency	No	R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards. It would also be beneficial to split this requirement into two requirements, one for real-time and one for Operational Planning Analysis since they are separate databases. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: (i) Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ...."; hence, the second use of Facilities in the phrase ought to be deleted, or at minimum, replaced with the term Elements; and (ii) although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 "mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. FMPA suggests clarifying who is mutually agreeing. Also, from a reliability perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14.R1.3 and R1.4 - should have the same characterization of R1.2,

Organization	Yes or No	Question 3 Comment
		e.g., "mutually" or stakeholder process driven to establish a schedule.
Response: In writing requirements such as these, there is a need to balance the need to recognize the many differences among entities verses the desire for explicit mandated behavior. To provide a list that meets one entity's data requirements will inevitably be too much or too little for another entity. Over the postings of this standard the Industry comments favored the flexibility approach. No change made. The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted. Mutually agreeable format is between the requesting entity and the entity being requested. There is no implied right given to a Transmission Operator or Balancing Authority to purchase tools that cannot be supported by the assets it coordinates. If there is a new technology that none of its members can support, must the members all be required to install new equipment for that change? The current sub-requirement has not been questioned by any other entity. No change made.		
City of Green Cove Springs	Ballot Comment	R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards. It would also be beneficial to split this requirement into two requirements, one for real-time and one for Operational Planning Analysis since they are separate databases. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: (i) Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ...."; hence, the second use of Facilities in the phrase ought to be deleted, or at minimum, replaced with the term Elements; and (ii) although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 "mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. GCS suggests clarifying who is mutually agreeing. Also, from a reliability related perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14. R1.3 and R1.4 - should have the same characterization of R1.2, e.g., "mutually" or stakeholder process driven to establish a

Organization	Yes or No	Question 3 Comment
		schedule. GCS believes significant changes to the standards are required; hence, it is too early to opine on the VSLs.
Response: In writing requirements such as these, there is a need to balance the need to recognize the many differences among entities verses the desire for explicit mandated behavior. To provide a list that meets one entity's data requirements will inevitable be too much or too little for another entity. Over the postings of this standard the Industry comments seem to favor the flexibility approach. No change made. The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted. Mutually agreeable format is between the requesting entity and the entity being requested. Requirement R1 must be viewed in the context that there "may be" more than one data specification used by a Transmission Operator or Balancing Authority. Requirement R1 allows the flexibility to customize specifications for each entity that is being asked to provide data for the operating analysis tools in question. No change made.		
Wisconsin Electric Power Company	No	R2 & R3 should not use the term monitored, the TOP or BA should distribute its data specification to all entities that are included in that specification to enable the proper Operational Planning Analyses and Real-time monitoring. R4 should not include both asset owners and operators, example generator xyz net output at the transmission interface needs to be the responsibility of one and only one entity to provide. Very confusing if both the GO and GOP have the same responsibility.
Response: The commenters provide no alternative to the term "monitored". Given the limited number of comments regarding this term, no change is made to the requirement. The SDT sees no problem with listing asset operators and owners in this requirement. Each entity will have received a different and specific data specification from the Transmission Operator or Balancing Authority so there should be no problem. No change made.		
Imperial Irrigation District	Yes	Suggestions/Comments: Could R2 & R3 be included as sub bullets of R1 (R1.1 & R1.2)? R1 - Each Transmission Operator and Balancing Authority shall have create and maintain a formal documented plan/procedure for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. R2 - Each Transmission Operator shall distribute its formal data plan/procedure specification to the Reliability Coordinator and entities that have Facilities monitored by the Transmission Operator and to entities that provide Facility status to the Transmission Operator.

Organization	Yes or No	Question 3 Comment
		R3 - Each Balancing Authority shall distribute its formal data plan/procedure specification to the Reliability Coordinator and to entities that have Facilities monitored by the Balancing Authority and to entities that provide Facility status to the Balancing Authority.
Response: The SDT believes that including Requirements R2 & R3 as sub-bullets would make Requirement R1 unmanageable and extremely difficult to measure. No change made. The SDT believes the suggested language does not provide any additional clarity. No change made. R2 & R3 - No justification for including the Reliability Coordinator was provided and the SDT sees no reliability reason to include the Reliability Coordinator in this process. No change made.		
Arizona Public Service Company	No	The need for the proposed “overarching” document is not necessary and appears cumbersome for many regions of the country such as the western interconnect.
Response: There is no mandate for an “overarching” document. The requirement is to provide document for any data that is needed for reliability. No change made.		
U.S. Bureau of Reclamation	Ballot Comment	The term "required" in requirement R1 "Each Transmission Operator and Balancing Authority shall have create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring." is not defined and does not encourage coordination amond the entities. It is suggested that coordination would be encouragedif an impartial entity provided oversight. The following language would resolve the undefined term and encourage coordination. "Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring as required by the requirements in the NERC Reliability Standards. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: o Long term outages of Bulk Electric System (BES) Facilities. o Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES. 1.2. A mutually agreeable format. 1.3. A periodicity for providing data. 1.4. The deadline by which the respondent is to provide the indicated data. 1.5. The specific NERC Reliability Standard requirement for which the data is needed. R5. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification will notify the Reliability Assurer if the data specifications are not consistent with

Organization	Yes or No	Question 3 Comment
		the NERC Reliability Standard Requirements. R6. The Reliability Assurer will review the data specifications for consistency with the NERC Reliability Standards and notify the Transmission Operator and Balancing Authority of the results and changes if any that are needed."
Response: The word "required" is used specifically in its traditional meaning relating to something that is critical and at the same time something that is missing. The wording of the requirement precludes the obligation of having documentation for data that an entity already has. Thus if a Transmission Operator has all the data it needs to do its reliability monitoring and its real time analysis, then no documentation specification is needed. However, when data is required, than a formal specification is mandated so that the entity receiving the request "knows" what is being requested. As written an auditor cannot arbitrarily ask for documentation of a specific piece of data that has been in use by a Transmission Operator and hold that Transmission Operator non-compliant for not having the specification. The fact that the data is in use serves as proof the data has been correctly obtained and received. No change made. Expanding a requirement to include procedural items does more to limit the flexibility and utilization of new technologies than it does to improve data exchange of current technologies. The two bulleted items under R1.1 of TOP-003-1 will be removed in the next posting. There are no data requirements in the current standards that cover the items in each and every analysis tool. Moreover, the current Reliability Standards Development process requires that all mandates be in the standard requirements themselves and not left as a fill-in-the-blank measure as defined by the subjectivity of a Reliability Assurer. No change made.		
NorthWestern Energy	Ballot Comment	TOP-003-2 We disagree with the new proposed version of the standard; the requirements obligate the Transmission Operator and Balancing Authority to create documented specifications for the data necessary to perform required Operational Planning Analysis and Real-time monitoring. This data is already spelled out and identified in the current version of TOP-003-1. The data requirements in the current standard TOP-003-1 have been tested and have been proven to be effective in gathering necessary data required by TOPs and BAs. The new proposed TOP-003-2 places a greater burden and responsibility on TOPs and BAs. If something is missed in the newly created specification for data necessary to perform Operational Planning Analysis, the responsibility falls on the TOP or BA alone.
Response: The word "required" is used specifically in its traditional meaning relating to something that is critical and at the same time something that is missing. No change made. If something is missed in the specification, the SDT believes that the onus should be on the Transmission Operator or Balancing Authority. The data requirements are thus defined by the Transmission Operator and not by an auditor. As written an auditor cannot arbitrarily ask for documentation of a specific piece of data that has been in use by a Transmission Operator and hold that Transmission Operator non-compliant for		

Organization	Yes or No	Question 3 Comment
not having the specification. The fact that the data is in use serves as proof the data has been correctly obtained and received. No change made.		
Lakeland Electric Beaches Energy Services	No	TOP-003-3: R1 - in general, "data necessary for it to perform its required Operational Planning Analysis and Real-time monitoring" is more ambiguous than the many requirements it replaced, and will probably be perceived by FERC as being too flexible a requirement that would allow a TOP or BA to do less than they are currently required. It may be beneficial to include a statement something like "including but not limited to:" and then include a bullet list of all the requirements it replaced in the prior version of the TOP standards to at least prove to FERC that we are not subtracting data/information requirements. R1.1, second bullet - although there is certainly a need to describe "operating parameters for BES Facilities and Facilities at voltage lower than the BES" there are two problems with the statement: 1. Facilities by definition are part of the BES, e.g., NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element ....” The second use of Facilities in the phrase ought to be deleted (see below), or at minimum, replaced with the term Elements. 2. Although there is certainly a need to describe operating parameters for non-BES equipment, there is no need to regulate that activity through the standards as it has no bearing on BES reliability. R1.2 “mutually" agreeable - who is mutually agreeing? R1 seems to imply the BA and TOP, but, the intent seems to be more in line with the entities described in R4, the BA, GO, GOP, IA, LSE, TOP, and TO. Suggest clarifying who is mutually agreeing. Also, from reliability related perspective, the TOP and BA needs to have final say if the entities cannot agree as a "backstop" provision. Suggest adding a stakeholder process something like what is in PRC-006-2 R14. R1.3 and R1.4 - should have the same characterization of R1.2, e.g., "mutually" or stakeholder process driven to establish a schedule.
Response: In writing requirements such as these, there is a need to balance the need to recognize the many differences among entities verses the desire for explicit mandated behavior. To provide a list that meets one entity’s data requirements will inevitable be too much or too little for another entity. Over the postings of this standard the Industry comments seem to favor the flexibility approach. No change made. The consensus of comments received in this posting supports removal of TOP-003-1, Requirement R1, bullet 2. As stated in the main requirement, the Transmission Operator or Balancing Authority can request whatever reliability-related data they need to perform their appointed tasks. Both bullets have been deleted.		

Organization	Yes or No	Question 3 Comment
Mutually agreeable format is between the requesting entity and the entity being requested. As has been cited in previous posting comment responses, the SDT believes that the entities involved will be reasonable in approaching a solution to a problem. However, if a resolution can't be reached, the disputing entities can always fall back on existing dispute resolution procedures administered by their Reliability Coordinator. No change made. This standard requires that data be requested when needed and that all parties come to a reasonable solution. If a resolution can't be reached, the disputing entities can always fall back on existing dispute resolution procedures administered by their Reliability Coordinator. No change made.		
Progress Energy	No	We perform many studies in different time frames that could be viewed as an "Operational Planning Analysis", from seasonal assessments, to OPC studies, to outage planning studies, day-ahead planning studies, real-time CA studies, etc. Our question is, which of these studies will be subject to all of the requirements in TOP1, 2, 3, and particularly to the data specification requirements in TOP-003? Will Transmission Operators be expected to meet these requirements for ALL studies, or can we designate one specific study process as the "Operational Planning Analysis" study (and, by implication, exempt others from the requirements). Also, TOP-003, R1 also includes "real-time monitoring" in the scope of the requirement for the data specification, so does this include the EMS and all of its data? This would require multiple data specifications, because the EMS and off-line PSS/E models we use to perform various studies would require different data specifications, have different contacts that provide information, etc.
Response: The commenter's first question is concerned about an auditor making the decision about what data must be specified. The word "required" is used in Requirement R1 specifically in its traditional meaning relating to something that is critical and at the same time something that is missing. The wording of the requirement precludes the obligation of having documentation for data that an entity already has. Thus if a Transmission Operator has all the data it needs to do its reliability monitoring and its Real-time analysis then no documentation specification is needed. However, when data is required for "any" of its analysis programs, then a formal specification is mandated so that the entity receiving the request "knows" what is being requested. It is up to the Transmission Operator or Balancing Authority to determine what data it needs to perform its studies. In other words, you select what data you need to perform your duties. There is no mandate for data specifications for data that a Transmission Operator already has. The standard does not specify which tools are considered as monitoring tools. If the EMS is defined as your monitoring tool then whenever additional data is needed, this standard requires the Transmission Operator to formally ask an entity for that data in the form and the time frame needed. The concern that a Transmission Operator will be found non-compliant because there is no one single document that covers all data is a misplaced concern. This requirement is written to be forward looking, not looking backward.		
City of Tallahassee	Ballot Comment	While it specifies that the examples are only possibilities for evidence, the inclusion of "with acknowledgement" to "web postings" in M2 & M3 for TOP-003-2 will become onerous. It

Organization	Yes or No	Question 3 Comment
		requires another entity to respond in order to have evidence we were compliant.
Response: The measurement language was linked to the closed-loop nature of some forms of evidence as opposed to other forms. When request and response is directly and independently documented there is no problem. However, the use of posting is indirect. In essence there is another step needed, i.e., to tell the other person the request is posted. Without that step an entity could be held non-compliant for something it never received a request for. The measurement merely requires that for a Transmission Operator to use that form, there is an added need to "prove" the other party knows the requests exists. No change made.		
Luminant Energy	No	While we agree with the concept of the TOP and BA creating a specification for data necessary for Operational Planning and Real-time monitoring, we feel that Requirement 1.2 should explicitly state that the format should be mutually agreeable to the TOP and BA and the parties receiving the data request under R2 and R3. Additionally, for R1.3, we feel the same mutually agreeable requirement between the TOP and BA and the parties receiving the data request should be added for the periodicity requirement.
Response: Mutually agreeable format is between the requesting entity and the entity being requested. The SDT believes this is clear with the existing wording. This applies to the periodicity element as well. No change made.		
American Electric Power	Yes	Additional clarity is needed as to the type(s) of data that would be considered necessary for performing operational planning analysis and real time monitoring. For example, will the requirements as specified in attachment 1 for TOP-005-2 be incorporated into TOP-003-1?
Response: Requirement R1 is actually quite specific – the data specification will include any and all data needed by a Transmission Operator or a Balancing Authority to fulfill their responsibilities. If the data is not on the list, then the data need not be supplied. However, the SDT has made clarifying changes to Requirements R2 & R3 that address this issue. As newly worded, this requirement limits the Transmission Operator to request only that data that it can make use of for reliability. In addition, it allows the Transmission Operator to request data from non-registered entities if needed as envisioned by FERC. The revised requirements focus on authorizing the Transmission Operator and Balancing Authority to request data that is needed for operating analysis of their respective areas with the data being limited to information required for that analysis. **R2.** Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements. **R3.** Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements .		
Northeast Utilities	Yes	Editorial comment: Remove "M5" because there is not any corresponding text and there is not a corresponding R5.

Organization	Yes or No	Question 3 Comment
Response: Agreed.		
Colorado Springs Utilities	Yes	Colorado Springs Utilities believes the question should be directed toward TOP-003-2.
Bonneville Power Administration	Yes	
Western Electricity Coordinating Council	Yes	
Southern Company	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Indeck Energy Services	Yes	
Oncor Electric Delivery	Yes	
ReliabilityFirst	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your support.		

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. Do you support the proposed VRF. VSL and Time Horizon assignments? If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The SDT made some changes to the VRFs, VSLs, and Time Horizons based on feedback received. Because these are compliance elements, they are not viewed as substantial changes to the standards.

One commenter requested a time frame for failing to inform per TOP-001-2, Requirement R2. The SDT made no change because each situation is different, preventing a universal time frame to inform.

The VSLs for TOP-001-2, Requirements R3, R5, and R6, TOP-002-3, Requirement R3, and TOP-003-2, Requirements R2 and R3, were modified to remove percentages. Some commenters found them confusing with both integer and percentage values. The sample sets are expected to be small enough that percentages will not work well.

The VSLs for TOP-001-2, Requirement R6 were further clarified to eliminate confusing language.

Several commenters expressed that VRFs, VSLs, and Time Horizons were not ready to be balloted until the requested changes to other parts of the standard were made. With the need to employ a successive ballot, this becomes a moot point.

Some commenters expressed that the High VRF associated with requirements to operate within the subset of non-IROL SOLs required to be identified per TOP-001-2, Requirement R8 should be changed to a Medium VRF. The SDT felt because these SOLs are viewed as being so important that a Transmission Operator must inform the Reliability Coordinator of them that the associated requirements warrant a High VRF as these SOLs are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined T_v, but must respect the Facility Rating or Stability criteria upon which they are based.

The Moderate and High VSLs for TOP-001-2, Requirement R8 were modified by changing the “or” between the ranges to an “and”. “Local” was replaced with “internal” for all of the VSLs to be consistent with the requirement.

Operations Planning and Same-day Operations were added to the TOP-001-2, Requirement R8 time horizon.

The VRF for TOP-002-3, Requirement R3 was changed to Medium.

For consistency, the VSL for TOP-001-2, Requirement R2 has been modified to match the language of the requirement more closely.

TOP-003-2, Requirement R1 VSLs were modified to include additional gradations for missing three and four or more parts of the requirement.

Several commenters were concerned about escalation of the VSLs associated with TOP-003-2, Requirement R4 for missing a few pieces of data. One even suggested the data should be prioritized based on unit size. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc., and no change was made. One commenter was concerned that VSLs for TOP-001-2, Requirement R6 do not consider small entities and suggested prioritizing of the VSLs based on unit size. The SDT believes VSLs do consider the impact on small entities. The SDT did not make any changes to prioritize the VSLs based on unit size because that is only applicable for adequacy and unit size is not relevant for transmission security.

One commenter requested the TOP-001-2, Requirement R1 Severe VSL should use an "or" condition rather than the "and" condition for failing to follow a directive and informing of the reason for not following the directive. The SDT felt the "and" condition was appropriate.

One commenter suggested that TOP-001-2, Requirement R6 was fundamentally modified to include data when telemetering equipment was changed to telemetry. The SDT agreed and modified the requirement accordingly.

TOP-001-2, R8: Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]

TOP-002-3, R3: Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor:Medium] [Time Horizon: Operations Planning]*

TOP-001-2, R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that

				Transmission Operator.

TOP-001-2, R3	The Transmission Operator did not inform one other Transmission Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators that are known or expected to be by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	1. The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. 2. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.

TOP-001-2, R5	The Transmission Operator did not inform one other Transmission Operator of its operations known or expected to result in an Adverse Reliability Impact on that respective Transmission Operator Area when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform four or more other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.

TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	3. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 4. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

TOP-001-2, R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability.	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability.

		area reliability.	area reliability.	
TOP-002-3, R3	The Transmission Operator did not notify one registered entity, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more registered entities identified in the plan(s) as to their role in the plan(s).
TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	5. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 6. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.

Organization	Yes or No	Question 4 Comment
City of Tacoma or Tacoma Public Utilities	No	1. TOP-001-2: In general, when "failure to inform" results in VSL, the timeframe for informing needs to be defined. 2. TOP-002-3, R3: The VSL language for all levels is confusing. At the minimum, the percentages for should be consistent between Lower, Moderate, High and Severe. 3. TOP-003-2: Similar to TOP-002-3, the VSL language for all levels is confusing and should be consistent between VSL levels.

Response: 1) The SDT disagrees with establishing a uniform time frame for response as each situation will be different. No change made.

2) and 3) The SDT concurs and has clarified the language.

TOP-002-3, R3	The Transmission Operator did not notify one registered entity, identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three registered entities identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more registered entities identified in the plan(s) as to their role in the plan(s).

Organization	Yes or No	Question 4 Comment
Duke Energy Carolina	Ballot Comment	4. The VRF, VSL, and Time Horizons are part of a non-binding poll. Do you support the proposed VRF. VSL and Time Horizon assignments? If you do not support these assignments or you agree in general but feel that

Organization	Yes or No	Question 4 Comment
		alternative language would be more appropriate, please provide specific suggestions in your comments. 1 No Comments: Consistent with our comments about the unacceptable phrase “supporting local area reliability” we do not support the VRFs and VSLs. 5.
Duke Energy	No	Consistent with our comments about the unacceptable phrase “supporting local area reliability” we do not support the VRFs and VSLs.
Response: Please see the SDT response to the “supporting local area reliability” issue in the associated comments for Q1.		
Ameren	No	As stated in comments above, we have concerns about the newly introduced term “internal” area reliability in TOP-001 and TOP-002 and proposed Medium VRF to the corresponding requirements.
Response: Please see our comments regarding the “internal” area reliability issue in the responses to Q1. The SDT believes the Medium VRF is appropriate as the SOLs that are identified by the Transmission Operator are important SOLs. No change made.		
Florida Municipal Power Agency	No	FMPA has no comments on the VRFs FMPA believes significant changes to the standards are

Organization	Yes or No	Question 4 Comment
		required; hence, it is too early to opine on the VSLs.
FirstEnergy	No	We cannot support the current VSL until our suggested changes to the requirements are made.
Response: Thank you for your response.		
Northeast Utilities	Yes	For TOP-001-2 Requirements R3, R5, R6 and R8, suggest changing "or' to "and" - that is change "...more than x% OR less than or equal to y%..." to "...more than x% AND less than or equal to y%..."
Northeast Power Coordinating Council Independent Electricity System Operator Hydro One Networks Inc	No	Referring to the Moderate and High VLSs for TOP-001-2 Requirements R3, R5, R6 and R8, where these VLSs state "...more than x% or less than or equal to y%...", suggest changing to ""...more than x% and less than or equal to y%...". These changes would also make these VLSs consistent with the language of TOP-002-3 and TOP-003-2.
Response: For Requirements R3, R5, and R6, the SDT decided to eliminate percentages in favor of integer VSL levels given the sample set sizes will likely be small even for a large Transmission Operator.		

TOP-001-2, R3	The Transmission Operator did not inform one other Transmission	The Transmission Operator did not inform two other Transmission	The Transmission Operator did not inform three other Transmission	7. The Transmission Operator did not inform its Reliability Coordinator of

Organization				Yes or No	Question 4 Comment
	Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	Operators that are known or expected to be by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. 8. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
TOP-001-2, R5	The Transmission Operator did not inform one other Transmission Operator of its operations known or expected to result in an Adverse Reliability Impact on that respective Transmission Operator Area when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform four or more other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment,	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of	9. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and

Organization	Yes or No	Question 4 Comment

	control equipment, and associated communication channels between the affected entities.	equipment,control equipment ,and associated communication channels between the affected entities.	telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	associated communication channels. 10. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

For Requirement R8, the recommended change was made and the percentage VSLs were retained as there is more uncertainty over the sample set sizes for this requirement.

Organization	Yes or No	Question 4 Comment
Puget Sound Energy	No	In TOP-001-2, R8, the time horizon should include Operations Planning and Same-day Operations, in addition to the currently-listed Real-Time Operations. In TOP-002-3, R3, the VRF is listed as “High”. However, according to the document “Violation Risk Factor and Violation Severity Level Assignments”, the appropriate level is “Medium”, which is also more consistent with the assignments associated with other requirements throughout these proposed standards. In TOP-002-3, the VSL matrix

Organization	Yes or No	Question 4 Comment
		entries associated with R3 need to have additional references to “reliability entities” changed to “registered entities”.
Response: The SDT has made the suggested changes to TOP-001-2, Requirement R8 and TOP-002-3, Requirement R3. **TOP-001-2, R8**: Each Transmission Operator shall inform its Reliability Coordinator of all SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]* **TOP-002-3, R3**: Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor:Medium] [Time Horizon: Operations Planning]* For the TOP-002-3, Requirement R3 VSL, no change was made because the VSLs already used the term registered entities as requested.		
ReliabilityFirst	No	ReliabilityFirst generally agrees with the Violation Risk Factors (VRFs) but disagrees with the Violation Severity Levels (VSLs) for the following reasons:TOP-001-2 VSLs1. VSL for R2a. The word “comply” is not within the language of R2 and should be removed from the VSL. R2 simply requires the Applicable Entities to “... inform its Transmission Operator...”. This is a violation of the FERC Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement” 2. VSL for R8a. The term “local area reliability” should

Organization	Yes or No	Question 4 Comment
		be replaced with “internal area reliability” to be consistent with the language in R8. This is a violation of the FERC Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement”TOP-003-21. VSL for R1a. The sub-parts should be referenced in the VSL. (i.e. “The responsible entity did not include one of the required elements, per Requirement R1, Parts 1.1 though Parts 1.4, of the documented specification...”) b. There is no provision if an Applicable Entity fails to include three or more of the required elements. VSLs should be gradated to include failure of including both three and four sub parts.

Response: The SDT does not believe any of the VSLs referenced are in violation of FERC guideline 3. The VSLs do not have to use the exact language of the requirement to be consistent. However, the SDT does recognize there is value in using the same wording to the extent possible for consistency. For TOP-001-2, Requirement R2, the SDT has modified the VSL to use language that is more consistent with the requirement.

For TOP-001-2, Requirement R8, the SDT has replaced local area reliability with internal area reliability for the VSL.

TOP-001-2, R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% and less than or equal to 10% of the SOLs	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% and less than or equal to 15% of the	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less,

Organization				Yes or No	Question 4 Comment
	IROL, has been identified by the Transmission Operator as supporting its internal area reliability**.**	whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability**.**	Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability**.**		which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability**.**
For TOP-003-2, Requirement R1, the VSLs do include the sub-parts. However, they were not fully gradated and the SDT has added VSLs for missing three and four elements.					
TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.		11. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 12. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.
LG&E and KU Energy PPL Supply				No	The Time Horizons seem to be inconsistent with established NERC definitions. The VSLs need to be updated with language modified in the requirements
Response: Without additional specificity on Time Horizons, the SDT is unable to make any changes.					

Organization	Yes or No	Question 4 Comment
For the VSLs, the SDT has made numerous changes as specified in other comments.		
Western Electricity Coordinating Council Imperial Irrigation District Arizona Public Service Company	No	These same comments were submitted with our vote on the non-binding VRF and VSL pollWECC agrees with the VRFs and the majority of the VSLs. However, we beleive consideration of the following will improve the VSLs.TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs to not appear to address the situation where the responsible entity did not include three or more of the required elements of the documented specification for the data necessary for it to perform its required Operations Planning

Organization	Yes or No	Question 4 Comment
		Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?
Response: For the VSLs for TOP-001-2, Requirement R6, the SDT has made clarifying changes.		

TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.	13. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 14. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated

Organization	Yes or No	Question 4 Comment
		communication channels between the affected entities.

For TOP-003-2, Requirement R1 VSLs, the SDT has added VSLs for missing three and four or more elements.

TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	15. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 16. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.

TOP-003-2, Requirement R4: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. No change made.

Organization	Yes or No	Question 4 Comment
Indeck Energy Services	No	TOP-001-2 R6: The VSL's do not consider the case of a small GOP (and possibly DP or LSE) which only affects the TOP or BA. The VSL needs

Organization	Yes or No	Question 4 Comment
		to reflect the significance of the planned outages. Planned outages of wind projects is of lower reliability significance than of large base load plants or black start units. The SDT needs to define the differences. Planned outages on GOP facilities that exceed the NERC Reportable Disturbance threshold for the BA would be Severe. Those between 75% & 100% of Reportable Disturbance would be High. Those between 50% and 75% of Reportable Disturbance would be Medium and all others would be Lower. TOP-003-2 R4: Only having Severe VSL avoids the difficult process of deciding what data is important. Data on outages of wind projects is of lower reliability significance than of large base load plants or black start units. The SDT needs to define the differences. Data on facilities that exceed the NERC Reportable Disturbance threshold for the BA would be Severe. Those between 75% & 100% of Reportable Disturbance would be High. Those between 50% and 75% of Reportable

Organization	Yes or No	Question 4 Comment
		Disturbance would be Medium and all others would be Lower.
Response: For TOP-001-2, Requirement R6, the SDT did attempt to address the case of the small Generator Operator, Transmission Operator or Balancing Authority by including the “x negatively impacted interconnected NERC registered entities”.. It did not attempt to address small Distribution Providers or Load-Serving Entities as the requirement does not apply to them. While it may be true that wind projects are of lower significance to adequacy than base load units, the SDT did not make any changes based on the size of the unit as the size of the unit may not be relevant to its importance to the transmission security of reliability. TOP-003-2, Requirement R4: All data can be important given the right circumstances. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended represent failure of small sets of data due to RTU outages, transducer issues, etc. No change made.		
Colorado Springs Utilities	No	TOP-001-2 R8 & R9 VRFs should be "Low"TOP-002-3; R2 - IROLs should be "High" / SOLs should be "Low". R3 should be "Medium".
Response: The SDT believes the Medium VRF is appropriate for TOP-001-2, Requirements R8 and R9 as the SOLs that are identified by the Transmission Operator are important SOLs. To have a lower VRF, the requirement would have to be administrative in nature per the definition of VRF. No change made. The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. The requirement is not mandating that a Transmission Operator must have such a subset but allows for that possibility to cover special concerns of the Transmission Operator such as environmental concerns, political importance, critical Loads, etc. Thus, the VRFs for TOP-002-3, Requirement R2 were not changed. The SDT had modified the VRF for TOP-002-3, Requirement R3 to Medium. **TOP-002-3, R3**: Each Transmission Operator shall notify all registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor:Medium] [Time Horizon: Operations Planning]*		
Bonneville Power Administration	No	TOP-003-2: The proposed

Organization	Yes or No	Question 4 Comment
		sanctions seem disproportionate to the offense. If a BA fails to contact an entity that influences its operation, the failure does not seem to affect anything except the evaluation's accuracy to the offending BA. Furthermore, it seems unlikely that a deliberate omission would be made since it's in a BA's best interest to have accurate assessments. TOP-001-2 R6: Clarification of the language and intent of Requirement R6 and the VSLs for R6 is needed. For example, it is difficult to determine if the Lower VSL for R6 is based on the responsible entity not notifying every negatively impacted entity of outages of equipment between the TOP and one (or 5%) affected entity, or if it is based on not telling one (or 5%) negatively impacted entity of outages. The same confusion exists in the remainder of the VSLs for R6. TOP-003-2 R1: The VSLs to not appear to address the situation where the responsible entity did not include three or more of the required elements of the

Organization	Yes or No	Question 4 Comment
		documented specification for the data necessary for it to perform its required Operations Planning Analyses and Real-time monitoring, but still had a documented specification. TOP-003-2 R4: The binary Severe VSL for R4 seems harsh. A responsible entity receiving a specification in Requirement R2 or R3 could have conceivably satisfied 99% of the obligations of the documented specifications for data and yet with this binary VSL, they would still be facing a Severe violation. Why are there not percentage graduations as in the other VSLs?

Response: TOP-003-2: The SDT is unsure of the specificity of your first comment. If you are referring to the percentage thresholds escalating quickly with 5% increments, these have been removed in favor of integer values.

TOP-001-2, Requirement R6: The SDT agrees with your comment and has made clarifying changes.

TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected	17. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 18. OR, The responsible entity did not notify four or more

Organization				Yes or No	Question 4 Comment
	entities.	affected entities.	entities.whichever is less.		negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
TOP-003-2, Requirement R1: The SDT agrees with your comment and has added VSLs for missing three and four or more elements.					
TOP-003-2, R1	The responsible entity did not include one of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring	The responsible entity did not include two of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.	The responsible entity did not include three of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.		19. The responsible entity did not include four or more of the required elements of the documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring. 20. 21. OR The responsible entity did not include a documented specification for the data necessary to perform its required Operational Planning Analyses and Real-time monitoring.
TOP-003-2, Requirement R4: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended represent					

Organization	Yes or No	Question 4 Comment
failure of small sets of data due to RTU outages, transducer issues, etc. No change made.		
Southern Company	Yes	(Please note that these comments relate to TOP-001-2). It is suggested that the R1 VSL Severity text be written as an either/or statement. “entity either did not comply with (a directive) or did not inform ....”R1, as its currently written, gives an entity these two choices. The R2 VSL Severe test is more expansive than Requirement 2. To match R2, it is suggested that the test read” ...entity did not inform the TOP of its inability to comply” The R6 graduated VSLs, as written, are hard to understand. For a given outage, it is unclear how many “affected entities” there are likely to be. Also for R6, the OR statement has conflicting scope (i.e. planned outage of telemetry OR with planned outage of telemetering equipment).
Response: No change was made to TOP-001-2, Requirement R1 Severe VSL because the “and” condition is appropriate. If the responsible entity does not comply it must also inform the Transmission Operator. With an “or” condition, failure to comply would be a Severe VSL even if the responsible entity informs the Transmission Operator. The SDT agrees with your assessment for the VSL for TOP-001-2, Requirement R2 and has modified it.		

Organization				Yes or No	Question 4 Comment
TOP-001-2, R2	N/A	N/A	N/A		The responsible entity did not inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
For the VSLs for TOP-001-2, Requirement R6, the SDT has made clarifying changes.					
TOP-001-2, R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment,control equipment ,and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment, and associated communication channels between the affected entities.whichever is less.		22. The responsible entity did not notify the Reliability Coordinator of its respective planned outages of telemetering equipment, control equipment, and associated communication channels. 23. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of its planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
R6: The SDT agrees with your comment. Consistent with your comments in Question 1, the SDT changed telemetry to telemetering equipment.					

Organization	Yes or No	Question 4 Comment
Luminant Energy	Yes	
Luminant Power	Yes	
American Electric Power	Yes	
Texas Reliability Entity	Yes	
Manitoba Hydro	Yes	
Lakeland Electric	Yes	
Oncor Electric Delivery	Yes	
Pepco Holdings Inc	Yes	
Cowlitz County PUD	Yes	
Oncor Electric Delivery	Yes	
Response: Thank you for your support.		

5. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: The comments in this section are mostly repeats of comments submitted for other questions. No changes were made to requirements for comments made exclusively for this question.

Organization	Yes or No	Question 1 Comment
NIPSCO		The new standard appears to treat SOLs and IROLs in a similar manner, which should not be the case. Also, in TOP-003-2 R1 1.1 the second bullet may incorrectly bring non-BES distribution facilities into play.
Response: The SDT agrees the subset of SOLs identified are treated similar to IROLs, except for the applicable mitigation timeframe. SOLs do not have a defined Tv, but must respect the Facility Rating or Stability criteria upon which they are based. No change made. The bullets in TOP-003-2 have been deleted.		
Imperial Irrigation District		1. The proposed versions of the standards appear to remove the redundancy and provide better clarity to the requirements. However the period when the proposed standard becomes effective is cumbersome.PROPOSED - Suggest two effective dates be provided? For example:Regulatory approval 05/01/2011Effective Date 10/01/2013Effective Date “Not Requiring Regulatory Approval” 10/01/2013CURRENT - Effective Date: All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption. 2. Recommend that the RSAWS for these proposed standards be revised and posted when the standard versions become effective. 3. Data Retention - Could the Data Retention be displayed in a matrix format (see example below) EXAMPLE Function Requirement Evidence Retention Period TOP R1 Compliance with RC Directives Current Year + Previous Year BA R2 Compliance with TOP Directive Current Year + 1 Year GOP R3 Compliance with TOP Directive

Organization	Yes or No	Question 1 Comment
		Current Year + 1
Response: The effective date language used is provided by NERC Legal and is not subject to change by an SDT. No change made. RSAWs are not within the scope of the SDT. They are a compliance item. The format shown for data retention is supplied by the template used by SDTs. The SDT did not receive any other comments in this regard and is reluctant to change the format at this point in time. The SDT suggests that you send your request for a different data retention format to the NERC Standards Process Manager for consideration. No change made.		
City of Tacoma or Tacoma Public Utilities		Comments: Please provide the definitions for new terms in the first version of the Standards. Once they have been introduced and/or the standard is undergoing a new revision - they could be removed to the Glossary for future reference.
Response: The only new term used in the standards is Reliability Directive and that is supplied with the document. No change made.		
Arizona Public Service Co.	Ballot Comment	The need for the proposed "overarching" document is not necessary and appears cumbersome for many regions of the country such as the western interconnect.
Response: There is no mandate for an "overarching" document. The requirement is to provide document for any data that is needed for reliability. No change made.		
Wisconsin Energy Corp.	Ballot Comment	TOP-001 R3 add to the requirement that the TOP will inform impacted Balancing Authorities. R4 it is unclear what is the nature of the emergency assistance that a TOP has available? I can understand a Distribution Provider shedding load, or a Generator Operator starting a generator or reducing output of a generator, these are not types of action a TOP may offer to others. R6 has the GOP notifying negatively impacted interconnected NERC registered entities, we do not support a GOP notifying anyone other then its RC, BA, and TOP. GOP should be removed from this requirement. In addition the phrase "negatively impacted interconnected NERC registered entities" is not clear enough to focus the notification on near term operations. R10 should add to the requirement that the TOP will inform impacted BA's of its actions R3 & R5 we think the subtle difference does not warrant separate requirements, the emergency in a TOP area vs conditions in a TOP area causing an Adverse

Organization	Yes or No	Question 1 Comment
		Reliability Impact on another's area, hence an emergency there is somewhat circular. TOP-002 R3 the TOP should provide the plan to its RC and BA (s) in addition to notifying other entities of expected actions. The use of the phrase "all registered entities" is too open ended, and not limited to operational functions as it should be. In addition some actions may be required of entities not registered. TOP-003 R2 & R3 should not use the term monitored, the TOP or BA should distribute its data specification to all entities that are included in that specification to enable the proper Operational Planning Analyses and Real-time monitoring. R4 should not include both asset owners and operators, example generator xyz net output at the transmission interface needs to be the responsibility of one and only one entity to provide. Very confusing if both the GO and GOP have the same responsibility.

Response: TOP-001, R3: The requirement is referring to transmission problems so the Balancing Authority doesn't have to be notified. No change made.

R4: The Transmission Operator could offer one or more of the following: Coordination actions by entities within its footprint; capacitor banks could be switched; topology could be altered; reactors could be switched; reactive injection changes by Generator Operators could be coordinated by the Transmission Operator as part of this response. No change made.

R6: The SDT has deleted Generator Operator from this requirement.

R10: This is a transmission function and not within the purview of the Balancing Authority so there is no need to notify them. No change made.

R3 & R5: Requirement R3 covers planning and Requirement R5 covers operations. Time horizons were changed to reflect this.

TOP-002, R3: The SDT has added the qualifier 'NERC' to the requirement to provide additional clarity.

TOP-003, R2 & R3: The Transmission Operator or Balancing Authority will only be requesting data from those it needs it from which will include all entities monitoring the equipment that the Transmission Operator or Balancing Authority is interested in. The SDT does not see any problem with the current language. No change made.

R4: The SDT sees no problem with listing asset operators and owners in this requirement. Each entity will have received a different and specific data specification from the Transmission Operator or Balancing Authority so there should be no problem. No change made.

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

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2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	4Q11
2. Post for recirculation ballot.	1Q12
3. Submit to BOT.	2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated on a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

A. Introduction

1. **Title:** **Coordination of Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

   4.5. Load-Serving Entity

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning,]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 . *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence that it complied with each identified Reliability Directive issued and identified as such by the Transmission Operator unless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified, Reliability Directive(s) issued in accordance with Requirement R2.

M3. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and Transmission Operators that it knew or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. Each Transmission Operator shall make available upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M5. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5 unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M6. Each Balancing Authority and Transmission Operator shall make available upon request, evidence that it notified the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to an electronic or hard copy of information from the Operational Planning Analysis used in its assessment, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based as specified in Requirement R8 and in Requirement R9. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 , in accordance with Requirement R11. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence to show compliance for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for three calendar months, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, unless such action would violate safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
R3	The Transmission Operator did not inform one other Transmission Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators that are known or expected to be by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.

	Lower	Moderate	High	Severe
For the Requirement R5 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R5	The Transmission Operator did not inform one other Transmission Operator of its operations known or expected to result in an Adverse Reliability Impact on that respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform its Reliability Coordinator of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
R6	The responsible entity did not notify one negatively impacted interconnected NERC registered entity of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of a planned outage of telemetering equipment, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more negatively impacted interconnected NERC registered entities of a planned outage of telemetering and control equipment and associated communication channels between the affected entities.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a

	Lower	Moderate	High	Severe
				continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability**.**
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v,}$ or of an SOL identified in Requirement R8.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

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Anticipated Actions	Anticipated Date
~~Post for ballot.~~	~~1Q11~~
1. Post for successive ballot.	4Q11
~~1.~~2. Post for recirculation ballot.	~~2~~1Q1~~1~~2
~~2.~~3. Submit to BOT.	~~3~~2Q1~~1~~2

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A. Introduction

1. **Title:** **Coordination of Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** ~~To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).~~ To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability**

   4.1. Balancing Authorit~~ies~~y

   4.2. Transmission Operator~~s~~

   4.3. Generator Operator~~s~~

   4.4. Distribution Provider~~s~~

   4.5. Load-Serving Entit~~ies~~y

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity~~, and Generator Operator~~ shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless ~~the respective entity informs its Transmission Operator that~~ such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity~~, and Generator Operator~~ shall inform its Transmission Operator ~~upon recognition~~ of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and ~~all other~~ Transmission Operators that are known or expected to be affected by each actual and anticipated Emergenc~~ies~~y based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning,~~Same-day Operations, Real-Time Operations~~]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. *[Violation Risk Factor: Medium] [Time Horizon: ~~Operations Planning,~~ Same-day Operations, Real-Time Operations]*

R6. Each Balancing Authority and Transmission Operator~~, Balancing Authority, and Generator Operator~~ shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetry~~telemetering equipment, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of ~~all~~each SOL~~s~~ which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration ~~exceeding 30 minutes~~ that would cause a violation of the Facility Rating or Stability criteria upon which it is based. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 ~~within 30 minutes~~. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity~~, and Generator Operator~~ shall make available upon request, evidence that it ~~either: (a)~~ complied with each identified Reliability Directive issued and identified as such by the Transmission Operator ~~or, (b) informed the Transmission Operator that~~nless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M2. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity~~, and Generator Operator~~ shall make available upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with ~~issued,~~ identified, Reliability Directive(s) issued in accordance with Requirement R2.

M3. Each Transmission Operator shall make available upon request, evidence that it has informed its Reliability Coordinator and ~~all other~~ Transmission Operators that it knew or expected to be affected by each actual and anticipated Emergenc~~ies~~y based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M4. Each Transmission Operator shall make available upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4 unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format.

M5. Each Transmission Operator shall make available upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5 unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M6. Each Balancing Authority and Transmission Operator~~, Balancing Authority, and Generator Operator~~ shall make available upon request, evidence that it notified the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of ~~telemetry~~telemetering equipment, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include but is not limited to an electronic or hard copy of information from the Operational Planning Analysis used in its assessment, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration ~~exceeding 30 minutes~~ that would cause a violation of the Facility Rating or Stability criteria upon which it is based as specified in Requirement R8 and in Requirement R9. Such evidence could include but is not limited to dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 ~~within 30 minutes~~, in accordance with Requirement R11.

Such evidence could include but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance ~~Violation~~ Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity~~, and Generator Operator~~ shall each keep data or evidence to show compliance for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year, with the exception of voice recordings which shall be retained for three calendar months, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has operated outside an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity~~, or Generator Operator~~ is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, ~~and the respective entity did not inform the Transmission Operator that~~ unless such action would violate safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity ~~did not comply with an identified Reliability Directive issued by its Transmission Operator, and the respective entity~~ did not inform ~~the~~its Transmission Operator of its inability to ~~do so~~perform an identified Reliability Directive issued by that Transmission Operator.
R3	The Transmission Operator did not inform one other ~~known or expected to be affected~~ Transmission Operator that is known or expected to be affected ~~or 5% or less of the other Transmission Operators known or expected to be affected whichever is less~~ by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other ~~known or expected to be affected~~ Transmission Operators that are known or expected to be ~~or more than 5% or less than or equal to 10% of the known or expected to be affected Transmission Operators whichever is less~~ by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other ~~known or expected to be affected~~ Transmission Operators that are known or expected to be affected ~~or more than 10% or less than or equal to 15% of the known or expected to be affected Transmission Operators whichever is less~~ by an actual or anticipated Emergency ~~-~~based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other ~~known or expected to be affected~~ Transmission Operators that are known or expected to be affected ~~or more than 15% of the known or expected to be affected Transmission Operators whichever is less~~ by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not

	Lower	Moderate	High	Severe
				render emergency assistance to other Transmission Operators, as requested and available, when the requesting entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
For the Requirement R5 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R5	The Transmission Operator did not inform one other Transmission Operator~~s~~ of its operations known or expected to result in an Adverse Reliability Impact on ~~those~~that respective Transmission Operator Areas ~~with one affected reliability entity or 5% or less of the affected reliability entities whichever is less~~ when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas ~~with two affected reliability entities or more than 5% or less than or equal to 10% of the affected reliability entities whichever is less~~ when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas ~~with three affected reliability entities or more than 10% or less than or equal to 15% of the affected reliability entities whichever is less~~ when conditions did permit such communications.	The Transmission Operator did not inform its Reliability Coordinator of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas ~~with four or more affected reliability entities or more than 15% of the affected entities whichever is less~~ when conditions did permit such communications.
R6	The responsible entity did not notify one negatively impacted interconnected NERC registered ~~entities~~entity of ~~its~~a ~~respective~~ planned outage~~s~~ of ~~telemetry~~telemetering equipment,	The responsible entity did not notify two negatively impacted interconnected NERC registered entities of ~~its~~a ~~respective~~ planned outage~~s~~ of telemetering equipment, ~~and~~ control equipment, and	The responsible entity did not notify three negatively impacted interconnected NERC registered entities of ~~its~~a ~~respective~~ planned outage~~s~~ of telemetering equipment, ~~and~~ control equipment and	The responsible entity did not notify ~~the~~its Reliability Coordinator of ~~its respective~~ a planned outage~~s~~ of ~~telemetry~~telemetering equipment, control equipment, and associated communication channels.

	Lower	Moderate	High	Severe
	control equipment, and associated communication channels between the affected entities ~~with~~ ~~one negatively impacted interconnected NERC registered entities or 5% or less of the affected entities whichever is less~~.	associated communication channels between the affected entities~~with two negatively impacted interconnected NERC registered entities or more than 5% or less than or equal to 10% of the affected entities whichever is less~~.	associated communication channels between the affected entities~~with three negatively impacted interconnected NERC registered entities or more than 10% or less than or equal to 15% of the affected entities whichever is less~~.	OR, The responsible entity did not notify ~~the Reliability Coordinator and negatively impacted interconnected NERC registered entities of its respective planned outages of telemetering and control equipment and associated communication channels with~~ four or more negatively impacted interconnected NERC registered entities ~~or more than 15% of the affected entities whichever is less~~of a planned outage of telemetering and control equipment and associated communication channels between the affected entities.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting its ~~local~~internal area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs or more than 5% or less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its ~~local~~internal area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs or more than 10% or less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its ~~local~~internal area reliability**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting its ~~local~~internal area reliability**.**
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration ~~greater than 30 minutes~~ that would cause a violation of the Facility Rating or Stability criteria

	Lower	Moderate	High	Severe
				upon which it is based.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v,}$ or of an SOL identified in Requirement R8 ~~within 30 minutes~~.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that 3 requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	4Q11
2. Post for recirculation ballot.	1Q12
3. Submit to BOT.	2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**
2. **Number:** TOP-002-3
3. **Purpose:** To ensure that Transmission Operators have plans for operating within specified limits.
4. **Applicability**

   4.1. Transmission Operator.
5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

Rationale for Requirement R1:

By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have a process for performing the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, it may be completed by procedures or by tools but if tools are used, the Transmission Operator must be able to complete the analysis even if those tools are not available.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis that represented projected System conditions allowing it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one NERC registered entity or 5% or less of the NERC	The Transmission Operator did not notify two NERC registered entities or more than 5% and less	The Transmission Operator did not notify three NERC registered entities or more than 10% and	The Transmission Operator did not notify four or more NERC registered entities or more 15% of

	registered entities identified in the plan(s) cited as to their role in the plan(s).	than or equal to 10% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	less than or equal to 15% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	the NERC registered entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
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2	TBD	Changes pursuant to Project 2007-03	Revised

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5. SAR approved by SC on November 1, 2007.
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8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. ~~The last draft was the fourth posting of the revised standards and represents one additional posting that was not anticipated.~~ As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that 3 requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~Post for ballot.~~	~~1Q11~~
1. Post for successive ballot.	~~3q11~~4Q11
2. Post for recirculation ballot.	~~3Q11~~1Q12
3. Submit to BOT.	~~4Q11~~2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. Title: **Operations Planning**

2. Number: TOP-002-3

3. Purpose: To ensure that Transmission Operators have plans for operating within specified limits.

4. Applicability

4.1. Transmission Operator.

5. Effective Date: All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale for Requirement R1:

~~Operational Planning Analysis (OPA) does not specifically cite additional Contingency analysis (which may be performed in Real-time), but the OPA contains system constraints which are based on a methodology that captures system Contingencies (FAC-011-2).~~

By stating this Requirement in this manner, the SDT is stating that a Transmission Operator must have a process for performing the Operational Planning Analysis (or has contracted the service). Since the Requirement does not mandate how the analysis is completed, it may be completed by procedures or by tools but if tools are used, the Transmission Operator must be able to complete the analysis even if those tools are not available.

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include but is not limited to dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has developed a plann~~ed~~ to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans~~, processes, or procedures~~ for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance ~~Violation~~ Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator ~~does~~did not have an Operational Planning Analysis that represented projected System conditions allowing it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not develop a plan to –operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one NERC registered entity or 5% or less of the NERC	The Transmission Operator did not notify two NERC registered entities or more than 5% and less	The Transmission Operator did not notify three NERC registered entities or more than 10% and	The Transmission Operator did not notify four or more NERC registered entities or more 15% of

	registered entities identified in the plan(s) cited as to their role in the plan(s).	than or equal to 10% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	less than or equal to 15% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	the NERC registered entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Changes pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that 3 requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	4Q11
2. Post for recirculation ballot.	1Q12
3. Submit to BOT.	2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**
2. **Number:** TOP-003-2
3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their operational planning and Real-time monitoring responsibilities.
4. **Applicability**
   - **4.1.** Transmission Operator.
   - **4.2.** Balancing Authority.
   - **4.3.** Generator Owner.
   - **4.4.** Generator Operator.
   - **4.5.** Interchange Authority.
   - **4.6.** Load-Serving Entity.
   - **4.7.** Transmission Owner.
5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

- **1.1.** A list of required data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.
- **1.2.** A mutually agreeable format.
- **1.3.** A periodicity for providing data.
- **1.4.** The deadline by which the respondent is to provide the indicated data.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

- **2.1.** A list of required data and information needed by the Balancing Authority to support its Real-time monitoring.
- **2.2.** A mutually agreeable format.
- **2.3.** A periodicity for providing data.
- **2.4.** The deadline by which the respondent is to provide the indicated data.

R3. Each Transmission Operator shall distribute its data specification to those entities that have data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority shall distribute its data specification to entities that have data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall make available its dated, current, in force documented specification for data in accordance with Requirement R1.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R2.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements in accordance with Requirement R4 and Measurement M4.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall retain evidence for 90 calendar days that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator did not include one of the required elements of the documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include two of the required elements of the documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include three of the required elements of the documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include four or more of the required elements of the documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.
R2	The Balancing Authority did not include one of the required elements of the documented specification for the data necessary for it to perform its required Real-time monitoring.	The Balancing Authority did not include two of the required elements of the documented specification for the data necessary for it to perform its required Real-time monitoring.	The Balancing Authority did not include three of the required elements of the documented specification for the data necessary for them to perform their required Real-time monitoring.	The Balancing Authority did not include four or more of the required elements of the documented specification for the data necessary for them to perform their required Real-time monitoring. OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its required Real-time monitoring.
R3	The Transmission Operator did not distribute its data specification to one entity or 5% or less of the entities whichever is less, that have data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements.	The Transmission Operator did not distribute its data specification to two entities or more than 5% and less than or equal to10% of the reliability entities whichever is less, that have data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements.	The Transmission Operator did not distribute its data specification to three entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that have data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements.	The Transmission Operator did not distribute its data specification to four or more entities or more than 15% of the entities whichever is less, that have data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements.

R4	The Balancing Authority did not distribute its data specification to one entity or 5% or less of the entities whichever is less, that have data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification to two entities or more than 5% and less than or equal to 10% of the entities whichever is less, that have data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements .	The Balancing Authority did not distribute its data specification to three entities or more than 10% and less than or equal to 15% of the entities whichever is less, that have data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements .	The Balancing Authority did not distribute its data specification to four or more entities or more than 15% of the entities whichever is less, that have data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements.
R5	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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6. First posting of revised standards on October 7, 2008.
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8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.

~~9.~~10. Fifth posting of revised standard on April 26, 2011.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. ~~The last draft was the fourth posting of the revised standards and represents one additional posting that was not anticipated.~~ As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that 3 requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
~~Post for ballot.~~	~~1Q11~~
1. Post for successive ballot.	4Q11
~~1.~~2. Post for recirculation ballot.	~~2~~1Q1~~1~~2
~~2.~~3. Submit to BOT.	~~3~~2Q1~~1~~2

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their ~~functional~~operational planning and Real-time monitoring responsibilities.

4. **Applicability**

   4.1. Transmission Operator~~s~~.

   4.2. Balancing Authorit~~ies~~y.

   4.3. Generator Owner~~s~~.

   4.4. Generator Operator~~s~~.

   4.5. Interchange Authorit~~ies~~y.

   4.6. Load-Serving Entit~~ies~~y.

   4.7. Transmission Owner~~s~~.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator ~~and Balancing Authority~~ shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of required data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring. ~~to be exchanged including, but not limited to:~~

~~Long term outages of Bulk Electric System (BES) Facilities.~~

~~Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES.~~

1.2. A mutually agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of required data and information needed by the Balancing Authority to support its Real-time monitoring.

2.2. A mutually agreeable format.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

~~R2.~~R3. Each Transmission Operator shall distribute its data specification to those entities that have ~~Facilities monitored~~data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~and to entities that provide Facility status to the Transmission Operator~~. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

~~R3.~~R4. Each Balancing Authority shall distribute its data specification to entities that have ~~Facilities monitored~~data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~and to entities that provide Facility status to the Balancing Authority~~. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

~~R4.~~R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~Transmission Operator,~~ and Transmission Owner receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator ~~and Balancing Authority~~ shall make available its dated, current, in force documented specification for data in accordance with Requirement R1.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R2.

~~M2.~~M3. Each Transmission Operator shall make available evidence that it has distributed its data specification to entities that have ~~Facilities monitored~~data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~and to entities that provide Facility status to the Transmission Operator~~ in accordance with Requirement R2. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

~~M3.~~M4. Each Balancing Authority shall make available evidence that it has distributed its data specification to entities that have ~~Facilities monitored~~data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~and to entities that provide Facility status to the Balancing Authority~~ in accordance with Requirement R3. Such evidence could include but is not limited to web postings with acknowledgement, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

~~M4.~~M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~Transmission Operator,~~ and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certification

Spot Checking

Compliance ~~Violation~~ Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator ~~and Balancing Authority~~ shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification to entities that have ~~Facilities monitored~~ data required by the Transmission Operator's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements ~~and to entities that provide Facility status to the Transmission Operator~~ in accordance with Requirement R~~2~~3 and Measurement M~~2~~3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have ~~Facilities monitored~~ data required by the Balancing Authority's reliability monitoring and operating analysis assessment processes and tools used in meeting its NERC-mandated reliability requirements ~~and to entities that provide Facility status to the Balancing Authority~~ in accordance with Requirement R~~3~~4 and Measurement M~~3~~4.
- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall retain evidence for 90 calendar days that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R~~4~~5 and Measurement M~~4~~5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The ~~responsible entity~~ Transmission Operator did not include one of the required elements of the documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	The ~~responsible entity~~ Transmission Operator did not include two of the required elements of the documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include three of the required elements of the documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring.~~N/A~~	The Transmission Operator did not include four or more of the required elements of the documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring. OR, The ~~responsible entity~~ Transmission Operator did not include a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.
R2	The Balancing Authority did not include one of the required elements of the documented specification for the data necessary for it to perform its required Real-time monitoring.	The Balancing Authority did not include two of the required elements of the documented specification for the data necessary for it to perform its required Real-time monitoring.	The Balancing Authority did not include three of the required elements of the documented specification for the data necessary for them to perform their required Real-time monitoring.	The Balancing Authority did not include four or more of the required elements of the documented specification for the data necessary for them to perform their required Real-time monitoring. OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its required Real-time monitoring.
R~~2~~3	The Transmission Operator did not distribute its data specification to one ~~reliability~~ entity or 5% or less of the ~~reliability~~ entities whichever is less, that have ~~Facilities monitored~~ data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~or that provide Facility~~	The Transmission Operator did not distribute its data specification to two ~~reliability~~ entities or more than 5% and less than or equal to10% of the reliability entities whichever is less, that have ~~Facilities monitored~~data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~or that provide Facility~~	The Transmission Operator did not distribute its data specification to three ~~reliability~~ entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that have ~~Facilities monitored~~data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability	The Transmission Operator did not distribute its data specification to four or more ~~reliability~~ entities or more than 15% of the entities whichever is less, that have ~~Facilities monitored~~data required by the Transmission Operator's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~or that provide Facility~~

	~~status to the Transmission Operator~~.	~~status to the Transmission Operator~~.	requirements ~~or that provide Facility status to the Transmission Operator~~.	~~status to the Transmission Operator~~.
R~~3~~4	The Balancing Authority did not distribute its data specification to one ~~reliability~~ entity or 5% or less of the entities whichever is less, that have ~~Facilities monitored~~ data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~and to one reliability entity or 5% or less of the reliability entities whichever is less that provide Facility status to the Balancing Authority~~.	The Balancing Authority did not distribute its data specification to two ~~reliability~~ entities or more than 5% and less than or equal to 10% of the entities whichever is less, that have ~~Facilities monitored~~data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~and to two reliability entities or more than 5% and less than or equal to 10% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority~~.	The Balancing Authority did not distribute its data specification to three ~~reliability~~ entities or more than 10% and less than or equal to 15% of the entities whichever is less, that have ~~Facilities monitored~~data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~and to three reliability entities or more than 10% and less than or equal to 15% of the reliability entities whichever is less, that provide Facility status to the Balancing Authority~~.	The Balancing Authority did not distribute its data specification to four or more ~~reliability~~ entities or more than 15% of the entities whichever is less, that have ~~Facilities monitored~~data required by the Balancing Authority's reliability monitoring tools used in meeting its NERC-mandated reliability requirements ~~and to four or more reliability entities or more than 15% of the reliability entities whichever is less that provide Facility status to the Balancing Authority~~.
R~~4~~5	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R~~2~~3 or R~~3~~4 did not satisfy the obligations of the documented specifications for data.

E. **Regional Variances**
None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-03 Real-time Operations

Prerequisite Approvals

Some changes made in this project are dependent on corresponding changes being approved in:

- Project 2006-06, Reliability Coordination:
  - IRO-001-3: Reliability Coordination – Responsibilities and Authorities
  - IRO-005-4: Reliability Coordination – Current Day Operations
- Project 2007-09, Generator Verification:
  - MOD-025-2 - Verification and Data Reporting of Generator Real and Reactive Power Capability

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

Two drafting teams (Project 2006-06 and Project 2007-03) have coordinated on a common definition of Reliability Directive and agreed that the Reliability Coordination Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference.

Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

Compliance with Standard

There are three standards associated with this project for which industry approval will be requested: TOP-001-2: Transmission Operations, TOP-002-3: Operations Planning, and TOP-003-1: Operational Reliability Data.

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							

TOP-001-2: Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X		X
TOP-004-2: Real-Time Transmission Operations	Retired							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-1: Response to Transmission Limit Violations	Retired							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

Effective Date of Revised Standards

All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

The twenty-four month period is to allow for entities to update processes, develop data specifications, and train operators on the revised requirements.

Retirement Date for Existing Standards

The existing Standards shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements will be retired at midnight of the day immediately prior to the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

Implementation Plan

Project 2007-03 Real-time Operations

Prerequisite Approvals

Some changes made in this project are dependent on corresponding changes being approved in:

- Project 2006-06, Reliability Coordination:
  - IRO-001-3: Reliability Coordination – Responsibilities and Authorities
  - IRO-005-4: Reliability Coordination – Current Day Operations
- Project 2007-09, Generator Verification:
  - MOD-025-2 - Verification and Data Reporting of Generator Real and Reactive Power Capability

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

Two drafting teams (Project 2006-06 and Project 2007-03) have coordinated on a common definition of Reliability Directive and agreed that the Reliability Coordination Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference.

Reliability Directive - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an ~~actual or expected~~ Emergency or Adverse Reliability Impacts.

Compliance with Standard

There are three standards associated with this project for which industry approval will be requested: TOP-001-2: ~~Coordination of~~ Transmission Operations, TOP-002-3: Operations Planning, and TOP-003-1: Operational Reliability Data.

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							
TOP-001-2: ~~Coordination of~~ Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X		X
TOP-004-2: Real-Time Transmission Operations	Retired							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-1: Response to Transmission Limit Violations	Retired							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

Effective Date of Revised Standards

All requirements will become effective the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

The twenty-four month period is to allow for entities to update processes, develop data specifications, and train operators on the revised requirements.

Retirement Date for Existing Standards

~~All requirements will be retired twenty-four months following the first day of the first quarter following regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements will be retired effective the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.~~ The existing Standards shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter twenty-four months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements will be retired at midnight of the day immediately prior to the first day of the first calendar quarter twenty-four months following Board of Trustees adoption.

~~Mapping Table~~

~~The following table indicates the disposition of the existing standards requirements related to this project.~~

~~TOP-001-1~~	
~~R1 - Existing~~	~~Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.~~
~~R1 - Resolution~~	~~Deleted – Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. Needed actions required for reliability of the bulk power system have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement.~~ ~~In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted~~
~~R1 – Reference~~	~~FERC Order 693a, paragraph 112:~~

	~~In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.~~
~~R2 - Existing~~	~~Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.~~
~~R2 - Resolution~~	~~This has been replaced by proposed TOP-001-2, Requirement R11. The undefined term 'operating emergencies' is no longer utilized and the requirement has been made more stringent by not restricting Transmission Operator actions to that undefined condition. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant timeframe.~~
~~R2 – Reference~~	~~TOP-001-2, R11:~~ ~~Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.~~
~~R3 - Existing~~	~~Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the~~

	~~directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.~~
~~R3 - Resolution~~	~~Deleted - This requirement is now covered in the proposed IRO-001-2, Requirements R2 & R3.~~
~~R3 – Reference~~	~~IRO-001-2, R2:~~ ~~Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts.~~ ~~IRO-001-2, R3:~~ ~~Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall comply with its Reliability Coordinator's direction per Requirement R2 unless the direction per Requirement R2 can not be implemented or such actions would violate safety, equipment, regulatory or statutory requirements.~~
~~R4 - Existing~~	~~Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.~~
~~R4 - Resolution~~	~~Retained and moved to proposed TOP-001-2, Requirement R1.~~
~~R4 – Reference~~	~~TOP-001-2, R1:~~ ~~Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.~~
~~R5 - Existing~~	~~Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.~~
~~R5 - Resolution~~	~~Retained and moved to proposed TOP-001-2, Requirement R3.~~

	~~The intent of the "mitigation" phrasing was replaced by proposed TOP-001-2, Requirement R11. (Also, see explanation for R2 above.)~~
~~R5 – Reference~~	~~TOP-001-2, R3:~~ ~~Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by actual and anticipated Emergencies based on its assessment of its Operational Planning Analysis.~~ ~~TOP-001-2, R11:~~ ~~Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.~~
~~R6 - Existing~~	~~Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.~~
~~R6 - Resolution~~	~~Retained and moved to proposed TOP-001-2, Requirement R4 for the Transmission Operator.~~ ~~The Generator Operator was removed since they can't be contacted directly by others and will only respond to such requests if they were in the form of a Reliability Directive from its Transmission Operator which is covered in proposed TOP-001-2, Requirement R1.~~ ~~The proposed EOP-001-2, Requirement R1 covers the Balancing Authority so to eliminate a redundancy the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission Operator as stated in proposed TOP-001-2, Requirement R1.~~
~~R6 – Reference~~	~~TOP-001-2, R6:~~ ~~Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.~~ ~~TOP-001-2, R1:~~ ~~Each Balancing Authority, Distribution Provider, Load-Serving Entity,~~

	~~and Generator Operator shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.~~ ~~EOP-001-2, R1:~~ ~~Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.~~
~~R7 - Existing~~	~~Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: 7.1 - For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. 7.2 - For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. 7.3 - When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.~~
~~R7 - Resolution~~	~~Retained but re-worded as part of proposed TOP-001-2, Requirement R5.~~ ~~After the fact notifications have been deleted since those actions will be seen through telemetry as cited in the proposed TOP-003-2 and proposed IRO-010-1a.~~ ~~The term 'burden' was considered by the SDT to be vague, ambiguous, unmeasurable, and undefined and has been replaced by a NERC defined term 'Adverse Reliability Impact'.~~
~~R7 – Reference~~	~~TOP-001-2, R5:~~ ~~Each Transmission Operator shall inform its Reliability Coordinator and~~

	~~other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.~~ ~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~ ~~IRO-010-1a, R1:~~ ~~The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages.~~ ~~Adverse Reliability Impact: The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.~~
~~R8 - Existing~~	~~During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.~~
~~R8 - Resolution~~	~~Real Power Balance and Reactive Power Balance are not defined terms.~~ ~~First sentence – Deleted due to: The Balancing Authority is covered in approved EOP-002-2.1, Requirement R6. Therefore, this portion of the requirement is redundant and can be deleted. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5. Approved VAR-001-1, Requirement R8 covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take~~

	~~actions regarding reactive power per the NERC Functional Model V5 (see proposed TOP-001-2, Requirement R1) and can therefore be deleted from this part of the requirement.~~ ~~Second sentence – Deleted due to: The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and can thus be deleted. Transmission Operators are covered under approved VAR-001-1, Requirement R1 thus making this part of the requirement redundant.~~ ~~Third sentence – The Reliability Coordinator is now covered in approved IRO-009-1, Requirements R1 and R2 and can be deleted here. The Transmission Operator and Balancing Authority are covered in approved EOP-003-1, Requirement R1. Therefore, this sentence is redundant and can be deleted.~~
~~R8 – Reference~~	~~EOP-002-2.1, R6:~~ ~~If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so.~~ ~~VAR-001-1, R8:~~ ~~Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.~~ ~~TOP-001-2, R1:~~ ~~Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.~~ ~~VAR-001-1, R1:~~ ~~Each Transmission Operator, individuallyand jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators~~ ~~IRO-009-1, R1:~~

	~~For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs.~~ ~~IRO-009-1, R2:~~ ~~For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is~~ ~~relieved within the IROL's Tv.~~ ~~EOP-003-1, R1:~~ ~~After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.~~
~~TOP-002-2~~	
~~R1 – Existing~~	~~Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.~~
~~R1 – Resolution~~	~~First sentence – Deleted for Balancing Authority, Retained for Transmission Operator -~~ ~~The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-0 and the proposed BAL-002-1 and must take action per approved EOP-002-2.1, Requirement R6 and thus can be deleted. Retained for Transmission Operator in proposed TOP-002-3, Requirements R1 through R3. This is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator.~~ ~~Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities as per~~

	~~their certification as NERC registered entities.~~
~~R1- Reference~~	~~BAL-001-0.1a, Purpose:~~ ~~To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.~~ ~~BAL-002-0, Purpose:~~ ~~The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.~~ ~~EOP-002-2.1, R6:~~ ~~If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so.~~ ~~TOP-002-3, R1:~~ ~~Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.~~ ~~TOP-002-3, R2:~~ ~~Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.~~ ~~TOP-002-3, R3:~~ ~~Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).~~
~~R2 – Existing~~	~~Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.~~
~~R2 – Resolution~~	~~The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and~~

	~~Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted.~~
~~R2 – Reference~~	~~Transmission Operator: The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.~~
~~R3 - Existing~~	~~Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.~~
~~R3 - Resolution~~	~~For all but the Transmission Service Provider, proposed TOP-003-2 requires the transfer of any and all data required for Real-time operations or Operational Planning Analyses regardless of timeframe involved. That makes this requirement redundant and it can be deleted.~~ ~~The Transmission Service Provider provisions are deleted due to:~~ • ~~Proposed MOD-001-1a, Requirement R1: Transmission Operators select transfer capability methodology from proposed MOD-028, -029, or -030.~~ • ~~Proposed MOD-030-2, Requirement R3: Transmission Operator gives transmission model updated at least once per day to Transmission Service Provider~~ ~~Proposed MOD-001-1a, Requirement R2: Transmission Service Providers use the methodology designated in proposed MOD-001-1a, Requirement R1 by the Transmission Operator.~~
~~R3 – Reference~~	~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~ ~~MOD-001-1a, R1:~~ ~~Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area:~~

	~~MOD-030-2, R3:~~ ~~The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria:~~ ~~MOD-001-1a, R2:~~ ~~Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s):~~
~~R4 - Existing~~	~~Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.~~
~~R4 - Resolution~~	~~Proposed TOP-003-2 requires the transfer of any and all data required for Real-time operations or Operational Planning Analyses between and amongst Balancing Authorities and Transmission Operators regardless of timeframe involved. That makes this requirement redundant and it can be deleted for Balancing Authorities and Transmission Operators.~~ ~~Data requirements for Reliability Coordinators are covered in approved IRO-010-1a, Requirement R3 making this requirement redundant for Reliability Coordinators so the Reliability Coordinator has been removed.~~
~~R4 – Reference~~	~~IRO-010-1a, R3:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.~~
~~R5 - Existing~~	~~Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.~~
~~R5 - Resolution~~	~~The Balancing Authority is covered by approved BAL-001-0.1a and thus can be deleted.~~ ~~The Functional Model requires a Balancing Authority to operate under~~

	~~the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority.~~ ~~The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R4.~~ ~~Transmission Operator - replaced by proposed TOP-002-3, Requirement R1.~~
~~R5 – Reference~~	~~BAL-001-0.1a, Purpose:~~ ~~To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.~~ ~~TOP-003-2, R4:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data.~~ ~~TOP-002-3, R1:~~ ~~Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.~~
~~R6 - Existing~~	~~Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.~~
~~R6 - Resolution~~	~~The Balancing Authority is covered by approved BAL-002-0 and proposed BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6 and thus can be deleted.~~ ~~The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity~~

	~~should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority.~~ ~~The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R4.~~ ~~Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. The n-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning.~~ ~~The SDT does not believe that there is a need for the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards.~~ ~~As stated in the NERC Functional Model V5: " the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation." To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and BAL-002-0 (and the proposed BAL-002-1), Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any system condition. Balancing Authorities are not responsible for the operation of the transmission system. The Transmission Operator is responsible for the real-time operating reliability of the transmission assets under its purview, and as such has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding load, generation and interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or load shedding). If the Balancing Authorities' actions do not resolve the transmission issues, it is the Transmission~~

	~~Operators' or Reliability Coordinators' responsibility to direct alternative actions.~~
~~R6 – Reference~~	~~BAL-002-0, R2:~~ ~~Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:~~ ~~BAL-002-0, R3:~~ ~~Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.~~ ~~BAL-002-0, R4:~~ ~~Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances.~~ ~~TOP-003-2, R4:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data.~~ ~~TOP-002-3, R1:~~ ~~Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.~~ ~~FAC-010-2.1, Purpose:~~ ~~To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.~~ ~~FAC-011-2, Purpose:~~ ~~To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.~~ ~~FAC-014-2, Purpose:~~ ~~To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.~~ ~~BAL-001-0.1a, Purpose:~~ ~~To maintain Interconnection steady-state frequency within defined limits by~~ ~~balancing real power demand and supply in real-time.~~ ~~BAL-002-0, Purpose:~~ ~~The purpose of the Disturbance Control Standard (DCS) is to ensure~~

	~~the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.~~
~~R7 – Existing~~	~~Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.~~
~~R7 – Resolution~~	~~The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-0 and the proposed BAL-002-1, Requirement R2 and therefore this requirement is redundant and can be deleted.~~ ~~Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations in the analysis.~~
~~R7 – Reference~~	~~BAL-002-0, R2:~~ ~~Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:~~ ~~TOP-002-3, R1:~~ ~~Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.~~
~~R8 – Existing~~	~~Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.~~
~~R8 – Resolution~~	~~The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and thus this requirement can be deleted.~~ ~~Voltage and reactive are the responsibility of the Transmission Operator and are covered under approved VAR-001-1, Requirement R1.~~

	~~Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is covered in proposed TOP-002-3, Requirement R1 since any deliverability problems will appear as limit violations in the analysis.~~
~~R8 – Reference~~	~~TOP-001-2, R1:~~ ~~Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements.~~ ~~VAR-001-1, R1:~~ ~~Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.~~ ~~TOP-002-3, R1:~~ ~~Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.~~
~~R9 - Existing~~	~~Each Balancing Authority shall plan to meet Interchange Schedules and ramps.~~
~~R9 - Resolution~~	~~This is covered in approved INT-003-2, Requirement R1 and is thus redundant and can be deleted.~~
~~R9 – Reference~~	~~INT-003-2, R1:~~ ~~Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.~~
~~R10 - Existing~~	~~Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).~~
~~R10 - Resolution~~	~~Balancing Authority - deleted as for transmission, the Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the Glossary and thus this requirement is not applicable to the Balancing Authority. The SDT position is that SOLs and IROLs are limits for which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to~~

	~~monitor SOLs, instructs the Balancing Authority as to what to do in these situations.~~ ~~Transmission Operator - covered in proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs).~~ ~~As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the bulk power system information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator.~~
~~R10 – Reference~~	~~TOP-002-3, R1:~~ ~~Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.~~ ~~TOP-002-3, R2:~~ ~~Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.~~
~~R11 - Existing~~	~~The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.~~
~~R11 - Resolution~~	~~Deleted:~~ ~~First sentence – SOLs are determined through the FAC-011-2 and FAC-014-2 processes so this sentence is no longer required.~~ ~~Second sentence - proposed TOP-003-2 requires the transfer of any~~

	~~and all data required for Real-time operations or Operational Planning Analyses.~~ ~~Third sentence – 'update… as necessary' is ambiguous and the SDT believes that proposed TOP-003-2 better covers this, so this is redundant and can be deleted.~~
~~R11 – Reference~~	~~FAC-011-2, Purpose:~~ ~~To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.~~ ~~FAC-014-2, Purpose:~~ ~~To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.~~ ~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~
~~R12 - Existing~~	~~The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.~~
~~R12 - Resolution~~	~~Deleted as duplicative of proposed MOD-028-1 and MOD-029-1.~~
~~R12 – Reference~~	~~MOD-028-2, Purpose:~~ ~~To increase consistency and reliability in the development and documentation of Transfer Capability calculations for short-term use performed by entities using the Area Interchange Methodology to support analysis and system operations.~~ ~~MOD-029-2, Purpose:~~ ~~To increase consistency and reliability in the development and documentation of transfer capability calculations for short-term use performed by entities using the Rated System Path Methodology to support analysis and system operations.~~
~~R13 - Existing~~	~~At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables,~~

	~~weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.~~
~~R13 - Resolution~~	~~Deleted as duplicative of proposed MOD-024-1 and MOD-025-1.~~
~~R13 – Reference~~	~~MOD-024-1, Purpose:~~ ~~To ensure accurate information on generator gross and net Real Power capability is available for steady-state models used to assess Bulk Electric System reliability.~~ ~~MOD-025-1, Purpose:~~ ~~To ensure accurate information on generator gross and net Reactive Power capability is available for steady-state models used to assess Bulk Electric System reliability.~~
~~R14 - Existing~~	~~Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: 14.1 - Changes in real and reactive output capabilities. (Retired August 1, 2007) 14.2 - Changes in real output capabilities. (Effective August 1, 2007) 14.3 - Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)~~
~~R14 - Resolution~~	~~Deleted – duplicative of proposed TOP-003-2, Requirement R4.~~
~~R14 – Reference~~	~~TOP-003-2, R4:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data.~~
~~R15 - Existing~~	~~Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).~~
~~R15 - Resolution~~	~~Deleted – duplicative of proposed TOP-003-2, Requirement R4.~~
~~R15 – Reference~~	~~TOP-003-2, R4:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement~~

	~~R2 or R3 shall satisfy the obligations of the documented specifications for data.~~
~~R16 - Existing~~	~~Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: 16.1 - Changes in transmission facility status. 16.2 - Changes in transmission facility rating.~~
~~R16 - Resolution~~	~~Deleted – duplicative of approved IRO-010-1a, Requirement R3.~~
~~R16 – Reference~~	~~IRO-010-1a, R3:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.~~
~~R17 - Existing~~	~~Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.~~
~~R17 - Resolution~~	~~Deleted - duplicative of approved IRO-010-1a, Requirement R3.~~
~~R17 – Reference~~	~~IRO-010-1a, R3:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.~~
~~R18 - Existing~~	~~Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.~~
~~R18 - Resolution~~	~~Deleted - this requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The SDT feels that the true reliability issue is not the name of a line but what is~~

	~~happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.~~
~~R18 – Reference~~	~~N/A~~
~~R19 - Existing~~	~~Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.~~
~~R19 - Resolution~~	~~Deleted - This is part of an entity's certification and is no longer required in standards. Furthermore, accuracy is a relative term that would be difficult to measure and assess compliance with. What is accurate? All calculated line flows are within 5% of actual flows? What if 14,999 lines out of 15,000 had calculated line flows within 5% and the 15,000th had a 6% error? Do we now call the model inaccurate and not rely on the results? How do you even define actual flows when meters have accuracy errors as well (i.e. no perfect meter exists)?~~
~~R19 - Reference~~	~~N/A~~
~~TOP-003-1~~	
~~R1 - Existing~~	~~Generator Operators and Transmission Operators shall provide planned outage information. 1.1 - Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. 1.2 - Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. 1.3 - Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200~~

	~~Pacific Standard Time for the Western Interconnection.~~
~~R1 - Resolution~~	~~Deleted as duplicative of proposed TOP-003-2, Requirement R1.~~
~~R1 - Reference~~	~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~
~~R2 - Existing~~	~~Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.~~
~~R2 - Resolution~~	~~Proposed TOP-001-2, Requirement R5 requires the Transmission Operator to coordinate while proposed TOP-003-2, Requirement R1 requires the Transmission Operator to identify the data it needs from the Balancing Authority to coordinate outages of voltage regulation equipment. Further, proposed TOP-003-2, Requirement R4 requires the Balancing Authority to provide the data to the Transmission Operator that the Transmission Operator identified it needs.~~
~~R2 – Reference~~	~~TOP-001-2, R5:~~ ~~Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.~~ ~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~ ~~TOP-003-2, R4:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data.~~
~~R3 - Existing~~	~~Each Transmission Operator, Balancing Authority, and Generator~~

	~~Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.~~
~~R3 - Resolution~~	~~Retained as proposed TOP-001-2, Requirement R6.~~
~~R3 – Reference~~	~~TOP-001-2, R6:~~ ~~Each Transmission Operator and Balancing Authority shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.~~
~~R4 - Existing~~	~~Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.~~
~~R4 - Resolution~~	~~Deleted – The proposed IRO-001-2, Requirement R2 and IRO-005-4, Requirement R1give the Reliability Coordinator the authority to resolve the conflict.~~
~~R4 - Reference~~	~~IRO-001-2, R2:~~ ~~Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts.~~ ~~IRO-005-4, R1:~~ ~~When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.~~
~~TOP-004-2~~	
~~R1 - Existing~~	~~Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).~~
~~R1 - Resolution~~	~~Moved to proposed TOP-001-2, Requirements R7 and R9.~~
~~R1 - Reference~~	~~TOP-001-2, R7:~~ ~~Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.~~ ~~TOP-001-2, R9:~~

	~~Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.~~
~~R2 – Existing~~	~~Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.~~
~~R2 – Resolution~~	~~Moved to proposed TOP-001-2, Requirements R7and R9.~~
~~R2 – Reference~~	~~TOP-001-2, R7:~~ ~~Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL~~ ~~T_v.~~ ~~TOP-001-2, R9:~~ ~~Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.~~
~~R3 – Existing~~	~~Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.~~
~~R3 – Resolution~~	~~Moved to proposed TOP-001-2, Requirements R7 and R9. These requirements are not limited by single or multiple Contingencies but are based solely on identified IROLs (and selected SOLs) regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator.~~
~~R3 – Reference~~	~~TOP-001-2, R7:~~ ~~Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL~~ ~~T_v.~~ ~~TOP-001-2, R9:~~ ~~Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.~~
~~R4 – Existing~~	~~If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations~~

	~~to respect proven reliable power system limits within 30 minutes.~~
~~R4 - Resolution~~	~~Deleted due to the fact that the SDT has determined a better way to handle such a situation is to treat it like an IROL or restoration scenario and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is covered under proposed TOP-001-2, Requirements R7 and R9 and the approved EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power system.~~
~~R4 - Reference~~	~~TOP-001-2, R7:~~ ~~Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.~~ ~~TOP-001-2, R9:~~ ~~Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.~~ ~~EOP-006-2, Purpose:~~ ~~Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained duringrestoration and priority is placed on restoring the Interconnection.~~
~~R5 - Existing~~	~~Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.~~
~~R5 - Resolution~~	~~The Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, thus this requirement is a moot point under the Functional Model definitions and can be deleted.~~
~~R5 – Reference~~	~~N/A~~
~~R6 - Existing~~	~~Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional~~

	~~reliability, including: 6.1 - Monitoring and controlling voltage levels and real and reactive power flows. 6.2 - Switching transmission elements. 6.3 - Planned outages of transmission elements. 6.4 - Responding to IROL and SOL violations.~~
~~R6 - Resolution~~	~~The first sentence was deleted as it is has been superseded by the NERC Reliability Standards taken as a whole. Examples of such would be the proposed TOP-001-2.~~ ~~The second sentence was deleted as all of the sub-requirements are covered elsewhere:~~ ~~R6.1 is duplicative of approved VAR-001-1, Requirement R1 for reactive. Real power flows are covered in proposed TOP-001-2, Requirements R7 and R9.~~ ~~R6.2 is covered in proposed TOP-001-2, Requirement R5~~ ~~R6.3 – moved to proposedTOP-001-2, Requirement R5;~~ ~~R6.4 – moved to proposed TOP-001-2, Requirement R11.~~
~~R6 - Reference~~	~~TOP-001-2, Purpose:~~ ~~To ensure coordination between and among reliability entities for the reliability of the Bulk Electric System (BES).~~ ~~VAR-001-1, R1:~~ ~~Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.~~ ~~TOP-001-2, R7:~~ ~~Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL~~ ~~T_v.~~ ~~TOP-001-2, R9:~~ ~~Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.~~ ~~TOP-001-2, R5:~~ ~~Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective~~

	~~Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.~~ ~~TOP-001-2, R11:~~ ~~Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.~~
~~TOP-005-2~~	
~~R1 - Existing~~	~~Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area. 1.1 - Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.~~
~~R1 - Resolution~~	~~Deleted – covered by approved IRO-010-1a, Requirement R3.~~
~~R1 – Reference~~	~~IRO-010-1a, R3:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.~~
~~R2 - Existing~~	~~As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."~~
~~R2 - Resolution~~	~~Confidentiality is not a reliability issue but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.~~
~~R2 - Reference~~	~~N/A~~
~~R3 - Existing~~	~~Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability~~

	~~assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.~~
~~R3 - Resolution~~	~~Deleted as redundant with proposed TOP-003-2, Requirement R4.~~
~~R3 - Reference~~	~~TOP-003-2, R4:~~ ~~Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data.~~
~~R4 - Existing~~	~~Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.~~
~~R4 - Resolution~~	~~Deleted as redundant to NAESB standard –All operating data that a Purchasing Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.~~
~~R4 - Reference~~	~~N/A~~
~~TOP-006-2~~	
~~R1 - Existing~~	~~Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. 1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. 1.2 - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.~~
~~R1 - Resolution~~	~~R1 & R1.1 - Deleted – covered as part of the data specification requirements in proposed TOP-003-2, Requirement R1.~~ ~~R1.2 - Deleted – covered by approved IRO-010-1, Requirement R3.~~
~~R1 - Reference~~	~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~

~~R2 – Existing~~	~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.~~
~~R2 - Resolution~~	~~Deleted – covered as part of the data specification requirements in proposed TOP-003-2, Requirement R1 for the Transmission Operator & Balancing Authority.~~ ~~The Reliability Coordinator is covered by approved IRO-010-1a, Requirement R1 and thus can be removed here.~~
~~R2 - Reference~~	~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~ ~~IRO-010-1a, R1:~~ ~~The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages.~~
~~R3 - Existing~~	~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.~~
~~R3 - Resolution~~	~~Deleted – as duplicative of proposed TOP-003-2 (data).~~
~~R3 - Reference~~	~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~
~~R4 - Existing~~	~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.~~
~~R4 - Resolution~~	~~Deleted – covered as part of the data specification requirements in proposed TOP-003-2, Requirement R1.~~ ~~Balancing Authority's must forecast their area's Load to meet control performance standards making this requirement redundant for Balancing Authority's.~~

~~R4 - Reference~~	~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~
~~R5 - Existing~~	~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.~~
~~R5 - Resolution~~	~~Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs; approved IRO-008-1, Requirement R2 for real-time assessments every 30 minutes for Reliability Coordinators.~~
~~R5 - Reference~~	~~BAL-005-01b, Purpose:~~ ~~This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.~~ ~~TOP-001-2, R10:~~ ~~Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded.~~ ~~IRO-008-1, R1:~~ ~~Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.~~
~~R6 - Existing~~	~~Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.~~
~~R6 - Resolution~~	~~Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE~~

	~~calculations (Balancing Authority); proposed TOP-001-2, Requirement R7 for Transmission Operator avoiding IROLs.~~
~~R6 - Reference~~	~~BAL-005-01b, Purpose:~~ ~~This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.~~ ~~TOP-001-2, R7:~~ ~~Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.~~
~~R7 - Existing~~	~~Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.~~
~~R7 - Resolution~~	~~Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, Requirement R2 for Transmission Operator avoiding underfrequency; approved EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators.~~
~~R7 – Reference~~	~~BAL-005-01b, Purpose:~~ ~~This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.~~ ~~EOP-003-1, R2:~~ ~~Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.~~ ~~EOP-006-2, R8:~~ ~~The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the~~

	~~resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization.~~
~~TOP-007-0~~	
~~R1 - Existing~~	~~A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.~~
~~R1 - Resolution~~	~~Moved to proposed TOP-001-2, Requirement R10.~~
~~R1 - Reference~~	~~TOP-001-2, R10:~~ ~~Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded.~~
~~R2 - Existing~~	~~Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.~~
~~R2 - Resolution~~	~~Moved to proposed TOP-001-2, Requirement R7~~
~~R2 - Reference~~	~~TOP-001-2, R7:~~ ~~Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL~~ $\cancel{T_v}$~~.~~
~~R3 - Existing~~	~~A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.~~ ~~EOP-003-1, R1:~~
~~R3 - Resolution~~	~~Deleted - Covered in approved EOP-003-1, Requirements R1 And proposed EOP-003-2, Requirement R1.~~
~~R3 – Reference~~	~~After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.~~
~~R4 - Existing~~	~~The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.~~

~~R4 - Resolution~~	~~Deleted as duplicative of approved IRO-008-1, Requirement R3.~~
~~R4 - Reference~~	~~IRO-008-1, R3:~~ ~~When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.~~
~~TOP-008-1~~	
~~R1 - Existing~~	~~The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.~~
~~R1 - Resolution~~	~~Deleted – as duplicative of EOP-003-1, Requirements R1 and proposed TOP-001-2, Requirement R11.~~
~~R1 - Reference~~	~~EOP-003-1, R1:~~ ~~After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection~~ ~~TOP-001-2, R11:~~ ~~Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8~~
~~R2 - Existing~~	~~Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.~~
~~R2 - Resolution~~	~~First sentence - Deleted as duplicative of proposed TOP-001-2, Requirements R7 and R9.~~ ~~Second sentence – deleted as this is now handled by the Reliability Coordinator as cited in approved IRO-009-1, Requirement R5.~~
~~R2 - Reference~~	~~TOP-001-2, R7:~~ ~~Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.~~ ~~TOP-001-2, R9:~~

	~~Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.~~ ~~IRO-009-1, R5:~~ ~~If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.~~
~~R3 - Existing~~	~~The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.~~
~~R3 - Resolution~~	~~Delete first sentence – Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. The SDT reaffirms that a standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse.~~ ~~Delete second sentence – no longer needed as first sentence was deleted.~~
~~R3 – Reference~~	~~N/A~~
~~R4 - Exisitng~~	~~The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.~~
~~R4 - Resolution~~	~~Deleted – information is covered as part of the data specification requirements in proposed TOP-003-2, Requirement R1. Analysis tools are covered in the certification process for initial core capabilities. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Operational~~

	~~Planning Analyses are required in proposed TOP-002-3, Requirement R1 while real-time analysis is required for IROL mitigation in proposed TOP-001-2, Requirement R7 thus covering the operational timeframes. Proposed TOP-001-2, Requirement R11 covers mitigation of limit violations.~~
~~R4 – Reference~~	~~TOP-003-2, R1:~~ ~~Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.~~ ~~TOP-002-3, R1:~~ ~~Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.~~ ~~TOP-001-2, R7:~~ ~~Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL~~ ~~T_v.~~ ~~TOP-001-2, R11:~~ ~~Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's~~ ~~T_v~~~~, or of an SOL identified in Requirement R8.~~
~~PER-001-0~~	
~~R1 - Existing~~	~~Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.~~
~~R1 - Resolution~~	~~Deleted - In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.~~
~~R1 – Reference~~	~~FERC Order 693a, paragraph 112:~~ ~~In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the~~

	~~current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.~~

Resolution of Issues Assigned to Project 2007-03 Real-time Operations Standard Drafting Team

Standard	Source	Language	Resolution
TOP-001			
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started. The TOP standards have been re-written to specifically address what a Transmission Operator is responsible for. The proposed TOP requirements are no longer restricted to the undefined term 'operating emergency' and are now more inclusive and stringent than the previous requirement. Indeed, the undefined term 'operating emergency' is no longer utilized in the proposed revisions. Therefore, any delay in defining operating states in the EOP Project has no effect on the TOP standards.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may	This is covered in proposed TOP-001-2, Requirement R5.

Standard	Source	Language	Resolution
		notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	Requirement using this term was deleted as not needed in a reliability standard. The standards already require the necessary actions.
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been re-written to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-002			
TOP-002-2	FERC Order 693	1600 - Address critical energy infrastructure confidentiality as part of the routine standard development process.	Restrictions due to confidentiality have been eliminated by re-writing the data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
TOP-00-2	FERC Order 693	1601 – Require next day analysis for all IROLs to identify and communicate control actions to system operators	See proposed TOP-002-3, Requirements R1, R2, and R3.
TOP-002-2	FERC Order 693	1603 - Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-002-2	FERC Order 693	1604/1608 - Requires simulation contingencies to match what will actually happen in the field.	This is covered in proposed TOP-002-3, Requirement R1 by the phrase "and shall represent projected System conditions".
TOP-002-2	FERC Order 693	1606 - Commenters did not take issue with the proposed interpretation of the term "deliverability" as "the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches."[1] The Commission adopts this proposed	Deliverability and limits are included in Operational Planning Analysis in TOP-002-3, Requirement R1. Operational Planning Analysis contains deliverability and much more and is thus more stringent than the Order. Limit violations in the Operational Planning Analysis will show any deliverability problems regardless of type and proposed requirements mandate

[1] Id. at P 974.

Standard	Source	Language	Resolution
		interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	that these issues be resolved. In addition, the proposed requirements clearly state that an individual entity, the Transmission Operator, is wholly responsible for these concerns which is an improvement over the previous vaguely worded requirement that placed this responsibility with the Balancing Authority which has no control over the issues involved.
TOP-002-1	Fill in the Blank Team	Remove "in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements" from R6 and "in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes" from R12 .	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. Requirement R12 has been deleted as duplicative of MOD-030-2 (not yet approved).
TOP-002-2: R19	NERC Audit Observation Team	How do you address the term - verify "Accurate"	Requirement R19 was eliminated as unmeasurable.
TOP-002-2	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1.
TOP-002-1	Version 0 Team	Define N-1	Requirement R6 has been deleted.

Standard	Source	Language	Resolution
			For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. This term is no longer in use for this standard.
TOP-002-1	Version 0 Team	Define 'without intentional delay'	This term was considered unmeasurable and has been deleted from this standard.
TOP-002-1	Version 0 Team	Reliability should 'trump' confidentiality	The SDT has removed all references to confidentiality by re-writing the data specification requirements.
TOP-002-1	Version 0 Team	Coordination of planning required	The SDT has re-written and tightened up the requirements for distributing data and information.
TOP-002-1	Version 0 Team	Limit of 2 tests per year	This requirement has been deleted by the SDT as verification testing is not needed in this standard.
TOP-002-1	VRF Team	R9 – related to INT-003	Requirement R9 has been deleted as it is duplicative of approved INT-003-2
TOP-002-1	VRF Team	R14 & 14.1 – ambiguous	Deleted – duplicative of proposed TOP-003-2.
TOP-002-1	VRF Team	R2 – administrative in nature, not a real requirement	The SDT agreed and deleted this requirement.
TOP-003			
TOP-003-0	FERC Order 693	1620 & 1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability	The SDT posed a question on this issue as a fact finding exercise in the second posting of this project in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by

Standard	Source	Language	Resolution
		Standard to incorporate an appropriate lead time for planned outages.	commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. After reviewing the industry comments, the SDT concluded that proposed TOP-001-2, Requirements R5 & R6 adequately cover this issue. The SDT bases this position on the requirement which includes the Operations Planning Time Horizon that covers the period from one day to one year. The requirement mandates that actions are coordinated. The SDT interprets this to include planned outages when they are known. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	FERC Order 693	1622 - Consider TVA's suggestion for including breaker outages within the	New data specifications in proposed TOP-003-2 handle this concern.

Standard	Source	Language	Resolution
		meaning of facilities that are subject to advance notice for planned outages.	
TOP-003-0	FERC Order 693	1624 - Require any facility, that in the opinion of the reliability coordinator, balancing authority, or transmission operator, will have a direct impact on the reliability of the bulk power system be subject to the requirement R1 for planned outage coordination.	New data specifications in proposed TOP-003-2, Requirement R1 (and bullets) handle this concern.
TOP-003-0	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1
TOP-003-0	Version 0 Team	Outage information needed sooner than 1 day prior	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	Version 0 Team	RA can't request outage cancellation	Deleted – now covered in Project 2006-06.
TOP-003-0	Version 0 Team	Submit outage data ASAP but no later than noon day ahead	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	VRF Team	R4 – poorly written	Deleted – now covered in Project 2006-06.
TOP-003-1	FMPA – Frank Gaffney	With respect to requirement R1.2, why is the TOP responsible for providing generator outage information? Isn't that the BA's or GOP's responsibility and isn't this redundant with IRO-010-1?	Requirement deleted as duplicative of proposed TOP-003-2, R1.

Standard	Source	Language	Resolution
TOP-004			
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	Replaced by proposed TOP-001-2, R7 through R11. T_v is more stringent than the existing 30 minute requirement for IROLs and 30 minutes is retained for selected SOLs. Unknown states, in this context, cannot exist because valid operating limits have been determined for all Facilities in a TOP's footprint. The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to Emergencies.
TOP-004-1	FERC Order 693	1637 - Reliability coordinators should report any IROL violations to NERC on a monthly basis for one year beginning August 2, 2007.	Not within the scope of the SDT.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (. . .the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or	The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the bulk power system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under . . . high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	FERC Order 693	1639 - Consider Santa Clara's comments regarding changes to requirement R2 in the standards development process. (Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.)	This is covered as part of the new data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by proposed IRO-010-1, Requirement R3.
TOP-004-1	FERC Order 693	1641 - NERC should report the results of the survey to the Commission within 18 months	Not within the scope of the SDT.

Standard	Source	Language	Resolution
		of the effective date of this rule.	
TOP-004-1	Fill in the Blank Team	No action required	No action required.
TOP-004-1	Version 0 Team	Operations should conform to planning standards	Operations and planning are different timeframes with different problems and solutions
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	Requirement moved to proposed TOP-001-2, Requirement R5 and clarified.
TOP-004-1	Version 0 Team	Define SOL & IROL	These are defined terms in the NERC Glossary.
TOP-004-1	Version 0 Team	Clarify roles	Applicability has been reviewed and updated as necessary.
TOP-004-1	Version 0 Team	Define (or remove) practical	The term has been removed.
TOP-004-1	Version 0 Team	Specify disconnection as acceptable in R5	The requirement has been deleted. Relationships between the Reliability Coordinator and Transmission Operator as described in the revised standards cover these actions.
TOP-005			
TOP-005-1	FERC Order 693	1648 - Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.
TOP-005-1	FERC Order 693	1649 - Delete references to confidentiality agreements but ensure critical energy infrastructure confidentiality is addressed in the standards development process.	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	FERC Order 693	1650 - Consider FirstEnergy’s modifications to Attachment 1 and ISO-NE’s recommended revision to requirement R4 in the standards	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.

Standard	Source	Language	Resolution
		development process. ISO-NE recommends that the reference to "purchasing-selling entity" in Requirement R4 should be replaced with "generator owner, transmission owner, and LSE.	Requirement R4 has been superseded by proposed TOP-003-2 which does include the indicated entities.
TOP-005-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R2 of PRC-001-1 in TOP-005. Note: These requirements are being removed from PRC.	See proposed TOP-003-2, Requirement R1
TOP-005-1	Version 0 Team	Need to include GO & LSE	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Data update is too slow	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Generator data should include voltage control & stabilizers	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	GO needs to supply data to BA & TO	New data specifications in proposed TOP-003-2 handle this concern
TOP-005-1	Received for the November 4, 2009 Technical Conference on Interpretations of Standards	NERC staff believes that the interpretation does not support the stated purpose of IRO-005-1: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The	While this issue was entered against the Transmission Operator as the interpretation request was primarily for TOP-005-1, the emphasis on such informative actions has shifted in current revision projects. The proposed IRO-010-1, Requirement R1 gives the Reliability Coordinator the right to ask for any reliability related data that they need to perform their Reliability Coordinator task.

Standard	Source	Language	Resolution
	from Manitoba Hydro	Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas." Given that Requirement R12 pre-supposes that the SPS is armed to address inter-Balancing Authority or inter-Transmission Operator impacts (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), the argument not discussed in the interpretation is that the SPS itself with one communication channel in service can be viewed for advance planning or reliability assessment purposes as a single contingency (loss of the communication channel). The question asked by the requestor indicates that the operation of the SPS on a single channel is known ahead of the timeframe for which the SPS may be armed and that the condition was not first identified when the SPS was called to operate. In this regard, the Reliability Coordinator must be aware of the less dependable state of the SPS in order to properly assess the impact and plan for the next single contingency that it conceivably could	And it also mandates the Transmission Operator to provide said data in Requirement R3. (Note – This standard has been approved by the BOT but has not yet been approved by FERC.)

Standard	Source	Language	Resolution
		experience. In this case, the Reliability Coordinator may wish to consider the loss of an armed SPS when performing its reliability assessments. While the Reliability Coordinator may not elect to proactively position the system to withstand the loss of the SPS that is operating on a single communication channel, the Reliability Coordinator may elect to develop a contingency plan in the event the SPS does fail to operate as designed or if the remaining communication channel is lost. The importance of the SPS relative to current or anticipated system conditions would be considerations for the Reliability Coordinator. This consideration only becomes possible if the Transmission Operator notifies the Reliability Coordinator that the SPS is operating on a single communication channel. Therefore, Transmission Operator notification to the Reliability Coordinator of this condition raises the Reliability Coordinator's situational awareness that may influence current or future operating conditions or decisions in a preventive rather than reactive manner. NERC staff does agree that the SPS	

Standard	Source	Language	Resolution
		is still mission capable with only one communication channel in service, but degraded in terms of its dependability due to the unavailability of redundant communications channels. The fact that a second communications channel was part of the original design of the SPS suggests that both channels were important to the dependability of the system, and that the unavailability of either channel causes some degradation in the overall dependability of the SPS. Additionally, the team equated "any degradation" with "potential failure to operate as expected" in IRO-005. The use of the term "or" connecting these two phrases in the standard indicates these were not intended to be equivalent. Therefore, NERC staff believes the conclusion reached by the team that the two terms are synonymous is incorrect. Further, the specific circumstances contemplated in the interpretation request are not likely to occur often and the additional burden to Transmission Operators to notify the Reliability Coordinator is de minimis when compared to the improved situational awareness that would result. On	

Standard	Source	Language	Resolution
		this basis, NERC staff believes the interpretation is not serving the best interests of reliability and should be remanded to the team for further consideration of the NERC staff opinion.	
TOP-006			
TOP-006-1	FERC Order 693	1660 & 1661 - Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system.	Minimum capabilities for Transmission Operators are being handled in project 2009-02, Real-time Monitoring and Analysis Capabilities. Requirement for phase angle information is covered by proposed TOP-003-2.
TOP-006-1	FERC Order 693	1663 - Clarify the meaning of "appropriate technical information" concerning protective relays. To provide more clarity, criteria that define what "appropriate technical information" is necessary should be specified so that operators can make better informed decisions.	This term is no longer used. Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and TOP-003-2 (data).
TOP-006-1	FERC Order 693	1664 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
TOP-006-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards.	See proposed TOP-003-2, Requirement R1

Standard	Source	Language	Resolution
		Consider putting R6 of PRC-001-1 in TOP-003 R5 or TOP-006. Note: These requirements are being retired in PRC-001-1.	
TOP-006-1	Version 0 Team	Need to match roles with FM	Applicability has been reviewed by the SDT and changed as required in accordance with the FM and the Compliance Registry.
TOP-006-1	Version 0 Team	Monitor frequency at multiple points	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	Load forecasting data required	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	GO needs to provide normal & emergency data	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R1, 1.1, 1.2 – 'available in emergency situation' may be needed	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R3 – define appropriate	This requirement was deleted as duplicative of approved PRC-001-1, Requirement R1.
TOP-006-1	VRFs Team	R4 – What information is required and what is a load pattern?	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirements R1 and R1.2, why are BAs responsible for information regarding transmission resources available for use? Isn't that the role of the TOP?	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R2, why is the BA responsible for monitoring transmission line status, voltage, load tap changer settings, and reactive power in general?	Deleted – SDT agrees.

Standard	Source	Language	Resolution
		Monitoring and managing reactive resources, voltage and tap settings is clearly made the responsibility of the TOP in VAR-001-1a.	
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R3 why does the BA need to understand protective relaying? Isn't that the role of the TOP and GOP?	Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and proposed TOP-003-2 (data).
TOP-007			
TOP-007-0	FERC Order 693	1673 - Consider the NRC's comments on voltage requirements as part of the standards development process.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-007-0	Version 0 Team	Need to define evidence of evaluation	This term isn't used in the requirements – no action required.
TOP-007-0	Version 0 Team	Need to tighten the non-compliance terms	Measures and VSL have been assigned to all requirements.
TOP-007-0	Version 0 Team	Not enforceable with current criteria	Not enough information provided to address concern.
TOP-007-0	Version 0 Team	RA should be included	Reliability Coordinator is now covered in Project 2006-06.

Standard	Source	Language	Resolution
TOP-007-0	Version 0 Team	More of a compliance issue than a true standard	Not enough information provided to address concern.
TOP-008			
TOP-008-1	FERC Order 693	1681 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
PER-001			
PER-001-0	Version 0 Team	Data retention should be 1 year	This standard will be retired.
Transferred from Project			
PRC-001	Project 2007-06	1441- S- Ref 10339 - Clarify the term corrective action. 1440. We believe that [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System. 1441. We direct the ERO to clarify the term corrective action consistent with this discussion when it modifies PRC-001-1 in the Reliability Standards development process.	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations.
PRC-001	Project 2007-06	1444 - S- Ref 10340 - Consider First Energy and the California PUCs comments about the	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations. The

Standard	Source	Language	Resolution
		maximum time for corrective actions in the standards development process. 1428. California PUC contends that imposing a time restriction for returning a system to a stable state may cause more harm than good since additional information and options may be available as time elapses. It repeats its suggestion from its earlier comments on the Staff Preliminary Assessment and proposes the following alternative language: Transmission or generation operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible, and no longer than 30 minutes, except where a longer response time is feasible, or where a longer response is demonstrated to produce a better ultimate solution without unacceptable interim risk. 1431. FirstEnergy contends that Requirement R2.1 essentially requires generator operators to report all protective relay or equipment failures, since generator operators may not be able to tell which failures will reduce system reliability. FirstEnergy suggests that R2.1 should be	Transmission Operator is the true functional entity responsible here. Covered as part of the new data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
		revised to require generator operators to report all equipment failures or outages. FirstEnergy further suggests that PRC-001-1 be revised to provide that if a company performs reasonable testing procedures, undiscoverable equipment failures will not be violations of R2.1	
PRC-001	Project 2007-06	1449 - S- Ref 10341 - Upon detection of failures in relays or protection system elements on the bulk power system that threaten reliability, relevant transmission operators must be informed promptly, but within a specified period of time. -- (2) a requirement that transmission and generator operators be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities could carry out appropriate corrective control actions consistent with those used in mitigating IROL violations.	Covered as part of the new data specification requirements in proposed TOP-003-2.
PRC-001	Project 2007-06	1449 - S- Ref 10343 - Para 1420. Once informed, transmission operators must carry out corrective control actions that return the system to a stable state that respects system requirements as soon as possible and no	Covered in TOP-001-2, Requirement R11.

Standard	Source	Language	Resolution
		longer than 30 minutes. 1440. [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.	

Resolution of Issues Assigned to Project 2007-03 Real-time Operations ~~SDT (Project 2007-03)~~Standard Drafting Team

Standard	Source	Language	Resolution
TOP-001			
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started. The TOP standards have been re-written to specifically address what a Transmission Operator is responsible for. The proposed TOP requirements are no longer restricted to the undefined term 'operating emergency' and are now more inclusive and stringent than the previous requirement. Indeed, the undefined term 'operating emergency' is no longer utilized in the proposed revisions. Therefore, any delay in defining operating states in the EOP Project has no effect on the TOP standards.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may	This is covered in proposed TOP-001-2, Requirement R5.

Standard	Source	Language	Resolution
		notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	Requirement using this term was deleted as not needed in a reliability standard. The standards already require the necessary actions.
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been re-written to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-002			
TOP-002-2	FERC Order 693	1600 - Address critical energy infrastructure confidentiality as part of the routine standard development process.	Restrictions due to confidentiality have been eliminated by re-writing the data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
TOP-00-2	FERC Order 693	1601 – Require next day analysis for all IROLs to identify and communicate control actions to system operators	See proposed TOP-002-3, Requirements R1, R2, and R3.
TOP-002-2	FERC Order 693	1603 - Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-002-2	FERC Order 693	1604/1608 - Requires simulation contingencies to match what will actually happen in the field.	This is covered in proposed TOP-002-3, Requirement R1 by the phrase ~~“…~~“and shall represent projected System conditions”.
TOP-002-2	FERC Order 693	1606 - Commenters did not take issue with the proposed interpretation of the term “deliverability” as “the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches.”[1] The Commission adopts this proposed	Deliverability and limits are included in Operational Planning Analysis in TOP-002-3, Requirement R1. Operational Planning Analysis contains deliverability and much more and is thus more stringent than the Order. Limit violations in the Operational Planning Analysis will show any deliverability problems regardless of type and proposed requirements mandate

[1] Id. at P 974.

Standard	Source	Language	Resolution
		interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	that these issues be resolved. In addition, the proposed requirements clearly state that an individual entity, the Transmission Operator, is wholly responsible for these concerns which is an improvement over the previous vaguely worded requirement that placed this responsibility with the Balancing Authority which has no control over the issues involved.
TOP-002-1	Fill in the Blank Team	Remove "in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements" from R6 and "in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes" from R12 .	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. Requirement R12 has been deleted as duplicative of MOD-030-2 (not yet approved).
TOP-002-2: R19	NERC Audit Observation Team	How do you address the term - verify "Accurate"	Requirement R19 was eliminated as unmeasurable.
TOP-002-2	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1.
TOP-002-1	Version 0 Team	Define N-1	Requirement R6 has been deleted.

Standard	Source	Language	Resolution
			For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. This term is no longer in use for this standard.
TOP-002-1	Version 0 Team	Define 'without intentional delay'	This term was considered unmeasurable and has been deleted from this standard.
TOP-002-1	Version 0 Team	Reliability should 'trump' confidentiality	The SDT has removed all references to confidentiality by re-writing the data specification requirements.
TOP-002-1	Version 0 Team	Coordination of planning required	The SDT has re-written and tightened up the requirements for distributing data and information.
TOP-002-1	Version 0 Team	Limit of 2 tests per year	This requirement has been deleted by the SDT as verification testing is not needed in this standard.
TOP-002-1	VRF Team	R9 – related to INT-003	Requirement R9 has been deleted as it is duplicative of approved INT-003-2
TOP-002-1	VRF Team	R14 & 14.1 – ambiguous	Deleted – duplicative of proposed TOP-003-2.
TOP-002-1	VRF Team	R2 – administrative in nature, not a real requirement	The SDT agreed and deleted this requirement.
TOP-003			
TOP-003-0	FERC Order 693	1620 & 1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability	The SDT posed a question on this issue as a fact finding exercise in the second posting of this project in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by

Standard	Source	Language	Resolution
		Standard to incorporate an appropriate lead time for planned outages.	commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. After reviewing the industry comments, the SDT concluded that proposed TOP-001-2, Requirements R5 & R6 adequately cover this issue. The SDT bases this position on the requirement which includes the Operations Planning Time Horizon that covers the period from one day to one year. The requirement mandates that actions are coordinated. The SDT interprets this to include planned outages when they are known. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	FERC Order 693	1622 - Consider TVA's suggestion for including breaker outages within the	New data specifications in proposed TOP-003-2 handle this concern.

Standard	Source	Language	Resolution
		meaning of facilities that are subject to advance notice for planned outages.	
TOP-003-0	FERC Order 693	1624 - Require any facility, that in the opinion of the reliability coordinator, balancing authority, or transmission operator, will have a direct impact on the reliability of the bulk power system be subject to the requirement R1 for planned outage coordination.	New data specifications in proposed TOP-003-2, Requirement R1 (and bullets) handle this concern.
TOP-003-0	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1
TOP-003-0	Version 0 Team	Outage information needed sooner than 1 day prior	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	Version 0 Team	RA can't request outage cancellation	Deleted – now covered in Project 2006-06.
TOP-003-0	Version 0 Team	Submit outage data ASAP but no later than noon day ahead	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	VRF Team	R4 – poorly written	Deleted – now covered in Project 2006-06.
TOP-003-1	FMPA – Frank Gaffney	With respect to requirement R1.2, why is the TOP responsible for providing generator outage information? Isn't that the BA's or GOP's responsibility and isn't this redundant with IRO-010-1?	Requirement deleted as duplicative of proposed TOP-003-2, R1.

Standard	Source	Language	Resolution
TOP-004			
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	Replaced by proposed TOP-001-2, R7 through R11. T_v is more stringent than the existing 30 minute requirement for IROLs and 30 minutes is retained for selected SOLs. Unknown states, in this context, cannot exist because valid operating limits have been determined for all Facilities in a TOP's footprint. The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to Emergencies.
TOP-004-1	FERC Order 693	1637 - Reliability coordinators should report any IROL violations to NERC on a monthly basis for one year beginning August 2, 2007.	Not within the scope of the SDT.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (. . .the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or	The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the bulk power system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under . . . high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	FERC Order 693	1639 - Consider Santa Clara's comments regarding changes to requirement R2 in the standards development process. (Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.)	This is covered as part of the new data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by proposed IRO-010-1, Requirement R3.
TOP-004-1	FERC Order 693	1641 - NERC should report the results of the survey to the Commission within 18 months	Not within the scope of the SDT.

Standard	Source	Language	Resolution
		of the effective date of this rule.	
TOP-004-1	Fill in the Blank Team	No action required	No action required.
TOP-004-1	Version 0 Team	Operations should conform to planning standards	Operations and planning are different timeframes with different problems and solutions
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	Requirement moved to proposed TOP-001-2, Requirement R5 and clarified.
TOP-004-1	Version 0 Team	Define SOL & IROL	These are defined terms in the NERC Glossary.
TOP-004-1	Version 0 Team	Clarify roles	Applicability has been reviewed and updated as necessary.
TOP-004-1	Version 0 Team	Define (or remove) practical	The term has been removed.
TOP-004-1	Version 0 Team	Specify disconnection as acceptable in R5	The requirement has been deleted. Relationships between the Reliability Coordinator and Transmission Operator as described in the revised standards cover these actions.
TOP-005			
TOP-005-1	FERC Order 693	1648 - Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.
TOP-005-1	FERC Order 693	1649 - Delete references to confidentiality agreements but ensure critical energy infrastructure confidentiality is addressed in the standards development process.	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	FERC Order 693	1650 - Consider FirstEnergy's modifications to Attachment 1 and ISO-NE's recommended revision to requirement R4 in the standards	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.

Standard	Source	Language	Resolution
		development process. ISO-NE recommends that the reference to "purchasing-selling entity" in Requirement R4 should be replaced with "generator owner, transmission owner, and LSE.	Requirement R4 has been superseded by proposed TOP-003-2 which does include the indicated entities.
TOP-005-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R2 of PRC-001-1 in TOP-005. Note: These requirements are being removed from PRC.	See proposed TOP-003-2, Requirement R1
TOP-005-1	Version 0 Team	Need to include GO & LSE	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Data update is too slow	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Generator data should include voltage control & stabilizers	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	GO needs to supply data to BA & TO	New data specifications in proposed TOP-003-2 handle this concern
TOP-005-1	Received for the November 4, 2009 Technical Conference on Interpretations of Standards	NERC staff believes that the interpretation does not support the stated purpose of IRO-005-1: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The	While this issue was entered against the Transmission Operator as the interpretation request was primarily for TOP-005-1, the emphasis on such informative actions has shifted in current revision projects. The proposed IRO-010-1, Requirement R1 gives the Reliability Coordinator the right to ask for any reliability related data that they need to perform their Reliability Coordinator task.

Standard	Source	Language	Resolution
	from Manitoba Hydro	Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas." Given that Requirement R12 pre-supposes that the SPS is armed to address inter-Balancing Authority or inter-Transmission Operator impacts (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), the argument not discussed in the interpretation is that the SPS itself with one communication channel in service can be viewed for advance planning or reliability assessment purposes as a single contingency (loss of the communication channel). The question asked by the requestor indicates that the operation of the SPS on a single channel is known ahead of the timeframe for which the SPS may be armed and that the condition was not first identified when the SPS was called to operate. In this regard, the Reliability Coordinator must be aware of the less dependable state of the SPS in order to properly assess the impact and plan for the next single contingency that it conceivably could	And it also mandates the Transmission Operator to provide said data in Requirement R3. (Note – This standard has been approved by the BOT but has not yet been approved by FERC.)

Standard	Source	Language	Resolution
		experience. In this case, the Reliability Coordinator may wish to consider the loss of an armed SPS when performing its reliability assessments. While the Reliability Coordinator may not elect to proactively position the system to withstand the loss of the SPS that is operating on a single communication channel, the Reliability Coordinator may elect to develop a contingency plan in the event the SPS does fail to operate as designed or if the remaining communication channel is lost. The importance of the SPS relative to current or anticipated system conditions would be considerations for the Reliability Coordinator. This consideration only becomes possible if the Transmission Operator notifies the Reliability Coordinator that the SPS is operating on a single communication channel. Therefore, Transmission Operator notification to the Reliability Coordinator of this condition raises the Reliability Coordinator's situational awareness that may influence current or future operating conditions or decisions in a preventive rather than reactive manner. NERC staff does agree that the SPS	

Standard	Source	Language	Resolution
		is still mission capable with only one communication channel in service, but degraded in terms of its dependability due to the unavailability of redundant communications channels. The fact that a second communications channel was part of the original design of the SPS suggests that both channels were important to the dependability of the system, and that the unavailability of either channel causes some degradation in the overall dependability of the SPS. Additionally, the team equated "any degradation" with "potential failure to operate as expected" in IRO-005. The use of the term "or" connecting these two phrases in the standard indicates these were not intended to be equivalent. Therefore, NERC staff believes the conclusion reached by the team that the two terms are synonymous is incorrect. Further, the specific circumstances contemplated in the interpretation request are not likely to occur often and the additional burden to Transmission Operators to notify the Reliability Coordinator is de minimis when compared to the improved situational awareness that would result. On	

Standard	Source	Language	Resolution
		this basis, NERC staff believes the interpretation is not serving the best interests of reliability and should be remanded to the team for further consideration of the NERC staff opinion.	
TOP-006			
TOP-006-1	FERC Order 693	1660 & 1661 - Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system.	Minimum capabilities for Transmission Operators are being handled in project 2009-02, Real-time Monitoring and Analysis Capabilities. Requirement for phase angle information is covered by proposed TOP-003-2.
TOP-006-1	FERC Order 693	1663 - Clarify the meaning of "appropriate technical information" concerning protective relays. To provide more clarity, criteria that define what "appropriate technical information" is necessary should be specified so that operators can make better informed decisions.	This term is no longer used. Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and TOP-003-2 (data).
TOP-006-1	FERC Order 693	1664 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
TOP-006-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards.	See proposed TOP-003-2, Requirement R1

Standard	Source	Language	Resolution
		Consider putting R6 of PRC-001-1 in TOP-003 R5 or TOP-006. Note: These requirements are being retired in PRC-001-1.	
TOP-006-1	Version 0 Team	Need to match roles with FM	Applicability has been reviewed by the SDT and changed as required in accordance with the FM and the Compliance Registry.
TOP-006-1	Version 0 Team	Monitor frequency at multiple points	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	Load forecasting data required	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	GO needs to provide normal & emergency data	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R1, 1.1, 1.2 – 'available in emergency situation' may be needed	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R3 – define appropriate	This requirement was deleted as duplicative of approved PRC-001-1, Requirement R1.
TOP-006-1	VRFs Team	R4 – What information is required and what is a load pattern?	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirements R1 and R1.2, why are BAs responsible for information regarding transmission resources available for use? Isn't that the role of the TOP?	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R2, why is the BA responsible for monitoring transmission line status, voltage, load tap changer settings, and reactive power in general?	Deleted – SDT agrees.

Standard	Source	Language	Resolution
		Monitoring and managing reactive resources, voltage and tap settings is clearly made the responsibility of the TOP in VAR-001-1a.	
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R3 why does the BA need to understand protective relaying? Isn't that the role of the TOP and GOP?	Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and proposed TOP-003-2 (data).
TOP-007			
TOP-007-0	FERC Order 693	1673 - Consider the NRC's comments on voltage requirements as part of the standards development process.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-007-0	Version 0 Team	Need to define evidence of evaluation	This term isn't used in the requirements – no action required.
TOP-007-0	Version 0 Team	Need to tighten the non-compliance terms	Measures and VSL have been assigned to all requirements.
TOP-007-0	Version 0 Team	Not enforceable with current criteria	Not enough information provided to address concern.
TOP-007-0	Version 0 Team	RA should be included	Reliability Coordinator is now covered in Project 2006-06.

Standard	Source	Language	Resolution
TOP-007-0	Version 0 Team	More of a compliance issue than a true standard	Not enough information provided to address concern.
		TOP-008	
TOP-008-1	FERC Order 693	1681 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
		PER-001	
PER-001-0	Version 0 Team	Data retention should be 1 year	This standard will be retired.
		Transferred from Project	
PRC-001	Project 2007-06	1441- S- Ref 10339 - Clarify the term corrective action. 1440. We believe that [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System. 1441. We direct the ERO to clarify the term corrective action consistent with this discussion when it modifies PRC-001-1 in the Reliability Standards development process.	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations.
PRC-001	Project 2007-06	1444 - S- Ref 10340 - Consider First Energy and the California PUCs comments about the	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations. The

Standard	Source	Language	Resolution
		maximum time for corrective actions in the standards development process. 1428. California PUC contends that imposing a time restriction for returning a system to a stable state may cause more harm than good since additional information and options may be available as time elapses. It repeats its suggestion from its earlier comments on the Staff Preliminary Assessment and proposes the following alternative language: Transmission or generation operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible, and no longer than 30 minutes, except where a longer response time is feasible, or where a longer response is demonstrated to produce a better ultimate solution without unacceptable interim risk. 1431. FirstEnergy contends that Requirement R2.1 essentially requires generator operators to report all protective relay or equipment failures, since generator operators may not be able to tell which failures will reduce system reliability. FirstEnergy suggests that R2.1 should be	Transmission Operator is the true functional entity responsible here. Covered as part of the new data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
		revised to require generator operators to report all equipment failures or outages. FirstEnergy further suggests that PRC-001-1 be revised to provide that if a company performs reasonable testing procedures, undiscoverable equipment failures will not be violations of R2.1	
PRC-001	Project 2007-06	1449 - S- Ref 10341 - Upon detection of failures in relays or protection system elements on the bulk power system that threaten reliability, relevant transmission operators must be informed promptly, but within a specified period of time. -- (2) a requirement that transmission and generator operators be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities could carry out appropriate corrective control actions consistent with those used in mitigating IROL violations.	Covered as part of the new data specification requirements in proposed TOP-003-2.
PRC-001	Project 2007-06	1449 - S- Ref 10343 - Para 1420. Once informed, transmission operators must carry out corrective control actions that return the system to a stable state that respects system requirements as soon as possible and no	Covered in TOP-001-2, Requirement R11.

Standard	Source	Language	Resolution
		longer than 30 minutes. 1440. [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.	

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-03 Real-time Operations

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001-2 – Coordination of Transmission Operations, TOP-002-3 – Operations Planning, and TOP-003-2 – Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in TOP-001-2, TOP-002-2, TOP-003-2:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eleven requirements in TOP-001-2. None of the eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, R4, R7, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Inability to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-005-4 that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions: IRO-001-2 for a Reliability Coordinator and TOP-001-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render emergency assistance could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-014-2 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities: TOP-001-2 for Transmission Operators and IRO-014-2 for Reliability Coordinators. The assignment of the Medium VRF was made based on the premise that failure to coordinate activities, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to coordinate activities. While the SDT agrees that, under some circumstances, it is possible that a failure to coordinate activities may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to coordinate would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to coordinate activities, it would still be expected to handle the situation if it occurred.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R6 has been assigned a Medium VRF and is the replacement (and a copy of) for approved TOP-003-1, Requirement R3.which was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or cascading failures
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R7 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R7 mandates that entities operate within each identified IROL and its associated IROL T_v. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- Bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF. FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R8 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission

Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R9 mandates that entities operate within each identified local SOL. Since SOLs, by definition, can't cause bulk power system instability, separation, or cascading this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, Requirements R7 and R9 which have High VRFs. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, Requirements R7, R9, and R11 and this requirement is a simple notification requirement for informational purposes only. Therefore, bulk power system instability, separation, or cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.

- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. Therefore, there is consistency among Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities act or direct others to act to mitigate the magnitude and duration of exceeding an IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

There are three requirements in TOP-002-3. All of the requirements were assigned a Medium VRF.

VRF for TOP-002-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-008-1 that is also assigned a Medium VRF. The requirements are viewed as similar since they both refer to preparing an Operational Planning Analysis: IRO-008-1 for a Reliability Coordinator and TOP-002-3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So, while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R2 is similar in scope to approved IRO-009-1, Requirement R1 which applies to the Reliability Coordinator while this requirement applies to the Transmission Operator. That requirement was assigned a medium VRF as has this requirement so there is consistency among the Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an operational planning requirement. So, in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R3 is similar to approved IRO-008-1, Requirement R3, the only difference being that the IRO standards refer to the Reliability Coordinator while the TOP standards are for the Transmission Operator. IRO-008-1, Requirement R3 is assigned a Medium VRF which is consistent with the assignment for TOP-002-3, Requirement R3.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of their roles in mitigating potential problems does not, in and of itself, lead to bulk power system instability, separation or cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3 Requirement R3 contains only one objective, therefore only one VRF was assigned.

There are five requirements in TOP-003-2. Four of the five requirements were assigned a "Lower" VRF - Requirements R1, R2, R3, and R4. Requirement R5 was assigned a "Medium" VRF.

VRF for TOP-003-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved IRO-010-1 that is also assigned a Lower VRF. The requirements are viewed as similar since they both refer to data specifications: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1 that is assigned a Lower VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2, Requirement R3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1 that is assigned a Lower VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2, Requirement R3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1 that is assigned a Lower VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved IRO-010-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator and Balancing Authority.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. However, it greatly increases the likelihood of such problems and therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-2, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R2. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the proposed IRO-005-4, Requirement R2. Those VSLs are also based on failure to notify reliability entities in a graduated scale from Lower to Severe. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the proposed IRO-014-2, Requirement R1. Those VSLs are also based on a graduated scale from Lower to Severe. The VSLs assignments are similar between the two standards. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-002-3 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved IRO-008-1, Requirement R1. That VSL is not binary as is the one proposed for this requirement. It proposes a graduated situation based on a number of days missing from the analysis. In looking at the VSL for this requirement, the SDT decided that it was an all or nothing situation – one either did the proper analysis or it didn't.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		Therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-002-3 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The requirement is similar to IRO-009-1, Requirement R1 which has a binary VSL (Severe only). The VSL for this requirement is also binary (Severe only). Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-002-3 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	TOP-002-3, Requirement R3 is similar to approved IRO-008-1, Requirement R3. The VSLs in that standard present a graded approach as does this proposal. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-010-1, Requirement R3. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-03 Real-time Operations

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001-2 – Coordination of Transmission Operations, TOP-002-3 – Operations Planning, and TOP-003-2 – Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in TOP-001-2, TOP-002-2, TOP-003-2:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eleven requirements in TOP-001-2. None of the eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, ~~R3,~~ R4, R7, ~~R9,~~ and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in proposed IRO-001-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a Reliability Directive: IRO-001-2 for a Reliability Directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Inability to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R~~4~~2) in proposed IRO-00~~1~~5-~~2~~4 that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions: IRO-001-2 for a Reliability Coordinator and TOP-001-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render emergency assistance could lead to bulk power system instability, separation or cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in proposed IRO-014-2 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities: TOP-001-2 for Transmission Operators and IRO-014-2 for Reliability Coordinators. The assignment of the Medium VRF was made based on the premise that failure to coordinate activities, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to coordinate activities. While the SDT agrees that, under some circumstances, it is possible that a failure to coordinate activities may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to coordinate would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to coordinate activities, it would still be expected to handle the situation if it occurred.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R6 has been assigned a Medium VRF and is the replacement (and a copy of) for approved TOP-003-1, Requirement R3.which was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or cascading failures
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R7 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R7 mandates that entities operate within each identified IROL and its associated IROL T_v. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- Bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF. FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R8 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission

Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R9 mandates that entities operate within each identified local SOL. Since SOLs, by definition, can't cause bulk power system instability, separation, or cascading this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, Requirements R7 and R9 which have High VRFs. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, Requirements R7, R9, and R11 and this requirement is a simple notification requirement for informational purposes only. Therefore, bulk power system instability, separation, or cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.

- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. Therefore, there is consistency among Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities act or direct others to act to mitigate the magnitude and duration of exceeding an IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

There are three requirements in TOP-002-3. ~~None of the three requirements were assigned a "Lower" VRF. Requirement R2 was assigned a "High" VRF while Requirements R1 & R3 were given a "Medium" VRF.~~All of the requirements were assigned a Medium VRF.

VRF for TOP-002-3, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in ~~proposed~~approved IRO-008-1 that is also assigned a Medium VRF. The requirements are viewed as similar since they both refer to preparing an Operational Planning Analysis: IRO-008-1 for a Reliability Coordinator and TOP-002-3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. This is an advanced planning requirement. So, while not having an Operational Planning Analysis could hinder the Transmission Operator, in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R2 is ~~a new requirement, so there are no comparable requirements with which to compare VRFs~~ similar in scope to approved IRO-009-1, Requirement R1 which applies to the Reliability Coordinator while this requirement applies to the Transmission Operator. That requirement was assigned a medium VRF as has this requirement so there is consistency among the Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. ~~Failure to preclude operating in violation of limits could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a High VRF.~~ This is an ~~advanced~~operational planning requirement. So, in and of itself, it does not directly affect the electrical state or the capability of the bulk power system and would not directly lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-002-3, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-002-3, Requirement R3 is ~~a new requirement, so there are no comparable requirements with which to compare VRFs~~ similar to approved IRO-008-1, Requirement R3, the only difference being that the IRO standards refer to the Reliability Coordinator while the TOP standards are for the Transmission Operator. IRO-008-1, Requirement R3 is assigned a Medium VRF which is consistent with the assignment for TOP-002-3, Requirement R3.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of their roles in mitigating potential problems does not, in and of itself, lead to bulk power system instability, separation or cascading failures. This is an advance planning requirement, not Real-time. The Transmission Operator still retains the operating requirements to preclude operating in exceedances of established limits. Thus, this requirement meets the criteria for a Medium VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-002-3 Requirement R3 contains only one objective, therefore only one VRF was assigned.

There are five requirements in TOP-003-2. ~~Three~~Four of the five requirements were assigned a "Lower" VRF - Requirements R1, R2, ~~and~~ R3, and R4. Requirement~~s~~ ~~R4 and~~ R5 ~~were~~was assigned a "Medium" VRF.

VRF for TOP-003-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in ~~proposed~~approved IRO-010-1 that is also assigned a Lower VRF. The requirements are viewed as similar since they both refer to data specifications: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to compile a data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in approved IRO-010-1 that is assigned a Lower VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2, Requirement R3 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R~~2~~3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in ~~proposed~~approved IRO-010-1 that is assigned a Lower VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2, Requirement R3 for a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Transmission Operator from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R~~3~~4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R2) in ~~proposed~~approved IRO-010-1 that is assigned a Lower VRF. The requirements are viewed as similar since they both refer to the distribution of the data specification: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Balancing Authority.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to distribute the data specification does not relieve a Balancing Authority from its responsibility to reliably operate the bulk power system so this requirement, in and of itself, does not directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. Therefore, this requirement is assigned a Lower VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-003-2, Requirement R~~4~~5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in ~~proposed~~approved IRO-010-1 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the provision of data: IRO-010-1 for a Reliability Coordinator and TOP-003-2 for a Transmission Operator and Balancing Authority.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to provide the data requested does not, in and of itself, directly affect the electrical state or the capability of the bulk power system and will not lead to bulk power system instability, separation, or cascading failures. However, it greatly increases the likelihood of such problems and therefore, this requirement is assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-003-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-2, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R2. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the proposed IRO-001-2, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the proposed IRO-005-4, Requirement R2. Those VSLs are also based on failure to notify reliability entities in a graduated scale from Lower to Severe. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the proposed IRO-014-2, Requirement R1. Those VSLs are also based on a graduated scale from Lower to Severe. The VSLs assignments are similar between the two standards. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-002-3 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	There is a similar requirement in approved IRO-008-1, Requirement R1. That VSL is not binary as is the one proposed for this requirement. It proposes a graduated situation based on a number of days missing from the analysis. In looking at the VSL for this requirement, the SDT decided that it was an all or nothing situation – one either did the proper analysis or it didn't.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		Therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-002-3 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance	The requirement is similar to IRO-009-1, Requirement R1 which has a binary VSL (Severe only). The VSL for this requirement is also binary (Severe only). Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-002-3 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	TOP-002-3, Requirement R3 is similar to approved IRO-008-1, Requirement R3. The VSLs in that standard present a graded approach as does this proposal. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1, Requirement R1. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to approved IRO-010-1, Requirement R2. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-003-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved IRO-010-1, Requirement R3. The proposed VSLs are similar in that they build on a graduated scale based on missing parts of the requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

A. Introduction

1. **Title:** **Operating Personnel Responsibility and Authority**

2. **Number:** PER-001-0.1

3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** December 10, 2009

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The job description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. **Compliance Monitoring Process**

   Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0.1	April 15, 2009	Replaced “position” with “job” on M1.1	Errata
0.1	December 10, 2009	Approved by FERC — added effective date	Update

A. Introduction

1. **Title:** **Reliability Responsibilities and Authorities**

2. **Number:** TOP-001-1

   Purpose: To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

3. **Applicability**

   3.1. Balancing Authorities

   3.2. Transmission Operators

   3.3. Generator Operators

   3.4. Distribution Providers

   3.5. Load Serving Entities

4. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:

R7.1. For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.2. For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.3. When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

C. Measures

M1. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.

M2. If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)

M3. Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)

M4. Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or

statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)

M5. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

M6. The Transmission Operator, Balancing Authority, and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)

M7. The Transmission Operator and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Balancing Authority:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

2.4.2 Did not render emergency assistance to others as requested, in accordance with R6.

3. Levels of Non-Compliance for a Transmission Operator

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Does not have the documented authority to act as specified in R1.

3.4.2 Does not have evidence it acted with the authority specified in R1.

3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.

3.4.4 Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.

3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.

3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.

3.4.7 Did not render emergency assistance to others as requested, as specified in R6.

3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

4. Levels of Non-Compliance for a Generator Operator:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.

4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.

4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity

5.1. Level 1: Not applicable.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable

5.4. Level 4: Did not comply with a Transmission Operator's reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Normal Operations Planning**
2. **Number:** TOP-002-2a
3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
4. **Applicability**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Operator.
   - **4.3.** Generator Operator.
   - **4.4.** Load Serving Entity.
   - **4.5.** Transmission Service Provider.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities. FERC Approved 12/2/09

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)

R14.1. Changes in real output capabilities. (Effective August 1, 2007)

R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Balancing Authorities:

2.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. Levels of Non-Compliance for Transmission Operators

3.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

3.2. Level 2: Not applicable.

3.3. Level 3: One or more of Bulk Electric System studies were not made available as specified in R11.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

3.4.3 Studies not updated to reflect current system conditions as specified in R11.

3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. Levels of Non-Compliance for Generator Operators:

4.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:

5.1. Level 1: Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject <u>to</u> …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation

Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a “unique” study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have “a” study that can be applied to it, but it is not necessary to generate a “unique” study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a “study”? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, “to determine SOLs” as used in the first sentence of Requirement R11 mean the “determination of system operating limits” or does it mean the “identification of potential SOL violations?”

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential “exceedances” of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.

A. Introduction

1. **Title:** **Planned Outage Coordination**

2. **Number:** TOP-003-1

3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

4. **Applicability**

   4.1. Generator Operators.

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

   4.4. Reliability Coordinators.

5. **Proposed Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information.

R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.

R1.2. Each Transmission Operator shall provide outage information daily to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.

R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, and Balancing Authority reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to "not be taken" because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Generator Operator failed to provide outage information, in accordance with its Transmission Operators established outage reporting requirements, to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW).
R1.1	N/A	N/A	N/A	The Transmission Operator failed to provide outage information, in accordance with its Reliability Coordinators established outage reporting requirement, to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.
R1.2	The responsible entity failed to provide the information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	N/A	N/A	N/A

R#	Lower	Moderate	High	Severe
R1.3	N/A	N/A	N/A	The responsible entity failed to plan or coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators when required.
R2	The responsible entity planned and coordinated scheduled outages of telemetering and control equipment and associated communication channels with its Reliability Coordinator, but failed to coordinate with affected neighboring Transmission Operators, Balancing Authorities, and Generator Operators.	N/A	N/A	The responsible entity failed to plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
R3	N/A	N/A	N/A	The Reliability Coordinator failed to resolve any scheduling of potential reliability conflicts.
R4	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 30 minutes but less than or equal to 35 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 35 minutes but less than or equal to 40 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 40 minutes but less than or equal to 45 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 45 minutes.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 23, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	

A. Introduction

1. **Title:** **Transmission Operations**

2. **Number:** TOP-004-2

3. **Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.

4. **Applicability:**

   4.1. Transmission Operators

5. **Proposed Effective Date:** Twelve months after BOT adoption of FAC-014.

B. Requirements

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.

R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.

R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

R6.1. Monitoring and controlling voltage levels and real and reactive power flows.

R6.2. Switching transmission elements.

R6.3. Planned outages of transmission elements.

R6.4. Responding to IROL and SOL violations.

C. Measures

M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.

M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data for Measure 1.

Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.

2.3. .**Level 3:** Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.

2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata

A. Introduction

1. **Title:** **Operational Reliability Information**

2. **Number:** TOP-005-2

3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Purchasing Selling Entities.

5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

   Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The ISN data recipient failed to sign the NERC Confidentiality Agreement for “Electric System Reliability Data”.
R2	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.
R3	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Removed the Reliability Coordinator from the list of responsible functional entities Deleted R1 and R1.1 Modified M1 to omit the reference to the Reliability Coordinator Deleted VSLs for R1 and R1.1	Revised
2	March 23, 2011	Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)	

Attachment 1-TOP-005

Electric System Reliability Data

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

1. The following information shall be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

1.1.1 Status.

1.1.2 MW or ampere loadings.

1.1.3 MVA capability.

1.1.4 Transformer tap and phase angle settings.

1.1.5 Key voltages.

1.2. Generator data.

1.2.1 Status.

1.2.2 MW and MVAR capability.

1.2.3 MW and MVAR net output.

1.2.4 Status of automatic voltage control facilities.

1.3. Operating reserve.

1.3.1 MW reserve available within ten minutes.

1.4. Balancing Authority demand.

1.4.1 Instantaneous.

1.5. Interchange.

1.5.1 Instantaneous actual interchange with each Balancing Authority.

1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.

1.5.3 Interchange Schedules for the next 24 hours.

1.6. Area Control Error and frequency.

1.6.1 Instantaneous area control error.

1.6.2 Clock hour area control error.

1.6.3 System frequency at one or more locations in the Balancing Authority.

2. Other operating information updated as soon as available.

2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.

2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.

2.3. Forecast peak demand for current day and next day.

2.4. Forecast changes in equipment status.

2.5. New facilities in place.

2.6. New or degraded special protection systems.

2.7. Emergency operating procedures in effect.

2.8. Severe weather, fire, or earthquake.

2.9. Multi-site sabotage.

A. Introduction

1. **Title:** **Monitoring System Conditions**

2. **Number:** TOP-006-2

3. **Purpose:** To ensure critical reliability parameters are monitored in real-time.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Generator Operators.

   4.4. Reliability Coordinators.

5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.

R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

C. Measures

M1. The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. (Requirement 1.2)

M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.

M4. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system's near-term load pattern. (Requirement 4)

M5. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)

M6. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift-operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measure 2.

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure 3, 5 and 6.

Each Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity failed to know the status of all generation and transmission resources available for use, even though said information was reported by the Generator Operator, Transmission Operator, or Balancing Authority.
R1.1	N/A	N/A	N/A	The Generator Operator failed to inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
R1.2	N/A	N/A	N/A	The responsible entity failed to inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
R2	N/A	The responsible entity monitors the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, but is not aware of the status of rotating and static reactive resources.	The responsible entity fails to monitor all of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of all rotating and static reactive resources.	The responsible entity fails to monitor any of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
R3	The responsible entity failed to provide any of the appropriate technical information concerning protective relays to their operating personnel.	N/A	N/A	The responsible entity failed to provide all of the appropriate technical information concerning protective relays to their operating personnel.

R#	Lower	Moderate	High	Severe
R4	N/A	N/A	The responsible entity has either weather forecasts or past load patterns, available to predict the system's near-term load pattern, but not both.	The responsible entity failed to have both weather forecasts and past load patterns, available to predict the system's near-term load pattern.
R5	N/A	N/A	The responsible entity used monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions, but does not have indication of the need for corrective action.	The responsible entity failed to use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions.
R6	N/A	N/A	N/A	The responsible entity failed to use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
R7	N/A	N/A	N/A	The responsible entity failed to monitor system frequency.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Modified R4 Modified M4 Modified Data Retention for M4 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	
2	March 23, 2011	Order issued by FERC approving TOP-006-2 (approval effective 5/23/11)	

A. Introduction

1. **Title:** Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations

2. **Number:** TOP-007-0

3. **Purpose:**

   This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.

R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.

R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.

R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

C. Measures

M1. Evidence that the Transmission Operator informed the Reliability Coordinator when an IROL or SOL was exceeded and the actions taken to return the system to within limits.

M2. Evidence that the Transmission Operator returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.

M3. Evidence that the Reliability Coordinator evaluated actions and provided direction required to return the system to within limits.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   The Reliability Coordinator shall report any IROL violation exceeding 30 minutes to the Regional Reliability Organization and NERC within 72 hours. Each Regional Reliability Organization shall report any such violations to NERC via the NERC compliance reporting process. The Reliability Coordinator shall report any SOL violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:

1.1.1. System instability.

1.1.2. Unacceptable system dynamic response or equipment tripping.

1.1.3. Voltage levels in violation of applicable emergency limits.

1.1.4. Loadings on transmission facilities in violation of applicable emergency limits.

1.1.5. Unacceptable loss of load based on regional and/or NERC criteria.

1.2. Compliance Monitoring Period and Reset Timeframe

The reset period is monthly.

1.3. Data Retention

The data retention period is three months.

2. Levels of Non-Compliance

2.1. The Transmission Operator did not inform the Reliability Coordinator of an IROL or an SOL that has become an IROL because of changed system conditions, and the actions they are taking to return the system to within limits, or

2.2. The Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the system to within the IROL within 30 minutes. (See Table 1-TOP-007-0 below.)

2.3. The limit violation was reported to the Reliability Coordinator, who did not provide appropriate direction to the Transmission Operator, resulting in an IROL violation in excess of 30 minutes duration.

Table 1-TOP-007-0 IROL and SOL Reporting Levels of Non-Compliance

Percentage by which IROL or SOL that has become an IROL is exceeded*	Limit exceeded for more than 30 minutes, up to 35 minutes.	Limit exceeded for more than 35 minutes, up to 40 minutes.	Limit exceeded for more than 40 minutes, up to 45 minutes.	Limit exceeded for more than 45 minutes.
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

*Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Response to Transmission Limit Violations**

2. **Number:** TOP-008-1

3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.

4. **Applicability**

   4.1. Transmission Operators.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.

R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

C. Measures

M1. The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)

M2. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1

M3. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)

M4. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents,

copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)

M5. The Transmission Operator that violates an SOL shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.

Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Transmission Operator

2.1. Level 1: Not applicable.

2.2. Level 2: Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.

2.4.2 Did not disconnect an overloaded facility as specified in R3.

2.4.3 Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)

2.4.4 Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comment Form for 6th Draft of Standards for Real-Time Operations (Project 2007-03)

Comments on the 6th draft and successive ballot of the standards for Real-Time Operations (Project 2007-03) must be submitted by **January 12, 2012.** If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information:

In the 6th posting for Project 2007-03, the Real-Time Operations Standard Drafting Team (RTOSDT) has attempted to clarify the proposed changes to the TOP family of standards based on industry comments received for the 5th posting and suggestions made during the Quality Review. Changes made were:

TOP-001-2:

- Changed the title of the standard to 'Transmission Operations' to better reflect the content of the standard.
- Based on Quality Review feedback changed the Purpose of the standard to more fully align with the requirements of the revised standard.
- Revised Requirement R1 to note that a Reliability Directive should be identified as such
- Deleted 'upon recognition' from Requirement R2
- Deleted 'all other' from Requirement R3
- Added Reliability Coordinator to Requirement R5
- Deleted Generator Operator from Requirement R6 and clarified that the requirement was for 'telemetry equipment'
- Deleted the 30 minute limit from Requirement R9 and replaced it with references to Facility Rating and Stability criteria
- Deleted the 30 minute limit from Requirement R11 to correspond with the change in Requirement R9
- Made a semantic change for clarity to Measure M2
- Changed the Time Horizons for Requirements R3, R5, and R8
- VSLs for Requirements R3, R5, and R6 were changed to move away from percentages
- The language for the VSLs in Requirements R2, R6, & R8 was clarified
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-002-3:

- Revised Requirement R2 to read as a positive statement rather than as a double negative
- Added the term “NERC” as a modifier of “registered entities” in Requirement R3
- Changed the VRF for Requirement R3 to Medium
- Modified the VSLs for Requirement R1
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-003-1:

- Based on Quality Review feedback, the Purpose of the standard has been modified to more fully align with the requirements of the revised standard.
- The bullets under Requirement R1, Part 1.1 have been deleted.
- Added new Requirement R2 to separate out the responsibilities of Balancing Authorities from Requirement R1.
- In response to Quality Review feedback, modified the language in Requirements R3 and R4 to clarify which data the Transmission Operator and Balancing Authority are to distribute.
- Made conforming changes to Measures to reflect changes to the Requirements.
- Based on Quality Review feedback, modified the Data Retention section to reflect the current NERC Rules of Procedure and Drafting Team Guidelines for evidence retention.
- Made conforming changes to VSLs to reflect changes to Requirements.

Other changes:

- The definition of Reliability Directive has been modified by Project 2006-06 to read as follows:

  “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.”

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No
   Comments:

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No
   Comments:

3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes
   ☐ No
   Comments:

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

☐ No

Comments:

5. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.

Comments:

Mapping Document

Project 2007-03 Real-time Operations

Mapping document showing the translation of TOP-001-1 — Reliability Responsibilities and Authorities; TOP-002-2 — Normal Operations Planning; TOP-003-1 — Planned Outage Coordination; TOP-004-2 — Transmission Operations; TOP-005-1 — Operational Reliability Information; TOP-006-1 – Monitoring System Conditions; TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations; TOP-008-1 - Response to Transmission Limit Violations; PRC-001-1 – System Protection Coordination; and PER-001-0 - Operating Personnel Responsibility and Authority.

Standard TOP-001-1 — Reliability Responsibilities and Authorities		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	Deleted	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the bulk power system have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement. In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, makes this requirement superfluous, and, thus, it can be deleted.

		FERC Order 693a, paragraph 112: "In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	Proposed TOP-001-2, Requirement R11	Replaced by proposed TOP-001-2, R11: The undefined term 'operating emergencies' is no longer utilized and the requirement has been made more stringent by not restricting Transmission Operator actions to that undefined condition. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant timeframe. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued	Proposed IRO-001-3, Requirements R2, R3 & R4.	Replaced by: IRO-001-3, R2. Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent

by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.		identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-001-3, R3. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall comply with its Reliability Coordinator's direction per Requirement R2 unless the direction per Requirement R2 cannot be implemented or such actions would violate safety, equipment, regulatory or statutory requirements. IRO-001-3, R4. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform as directed per Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	Proposed TOP-001-2, Requirements R1 & R2	Replaced by proposed: TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. TOP-001-2, R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate	Proposed TOP-001-2, Requirement R3 Proposed TOP-001-2, Requirement R11.	Replaced by proposed: TOP-001-2, R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis.

the emergency.		TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant timeframe.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	Proposed TOP-001-2, Requirement R4 for the Transmission Operator. Approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 for the Balancing Authority	Replaced by proposed TOP-001-2, R4. TOP-001-2, R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Generator Operator was deleted from this requirement since it can't be contacted directly by others and will only respond to such requests if they were in the form of a Reliability Directive from its Transmission Operator which is covered in proposed TOP-001-2, Requirement R1. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 covers the Balancing Authority so to eliminate a redundancy the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission Operator as stated in proposed TOP-001-2, Requirement R1. EOP-001-2b, R1. Balancing Authorities shall have

		operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: R7.1 - For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.2 - For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.3 - When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R5	R7: Replaced by proposed TOP-001-2, R5 for the Transmission Operator. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. R7 – The Generator Operator can't know if their actions will burden neighboring systems since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring systems and is required to act on this information as per proposed TOP-001-2, R5. R7.1 – Replaced by proposed TOP-001-2, R5 for both the Transmission Operator and the Generator Operator. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. R7.2 - Replaced by proposed TOP-001-2, R5 for the Transmission Operator. After the fact notifications have been replaced by the proposed TOP-003-2, R1 and approved IRO-010-1a since those actions will now be seen through telemetry.

notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.		TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages.
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	Approved EOP-002-3, Requirement R6. Approved VAR-001-1, Requirement R8. Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirements R1, R8, and R12. Approved IRO-009-1, Requirements R1 and R2. Approved EOP-003-1, Requirement R1.	Real Power Balance and Reactive Power Balance are not defined terms. First sentence – real power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance real power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – reactive power: Replaced by Approved VAR-001-1, Requirement R8 for the Transmission Operator which covers reactive power requirements and the meaning of balancing reactive power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power per the NERC Functional Model V5 (see proposed TOP-001-2, Requirement R1) and therefore the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the

		Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and thus the Balancing Authority is not necessary. Replaced by approved VAR-001-1, Requirements R1, R8, and R12 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-1, Requirement R1 for the Transmission Operator and Balancing Authority. EOP-002-3, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. VAR-001-1 R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. VAR-001-1, R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits. VAR-001-1, R12. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

		TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. IRO-009-1, R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) that can be implemented in time to prevent exceeding those IROLs. IRO-009-1, R2.For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions it shall take or actions it shall direct others to take (up to and including load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
Standard TOP-002-2 — Normal Operations Planning		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate	Approved BAL-001-0.1a. Approved BAL-	First sentence – Deleted for Balancing Authority, retained for Transmission Operator. The Balancing Authority is required to balance by

options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	002-1. Approved EOP-002-2.1, Requirement R6. Proposed TOP-002-3, Requirements R1 through R3.	approved BAL-001-0.1a and approved BAL-002-1 and must take action per approved EOP-002-2.1, Requirement R6 and thus the Balancing Authority part of this sentence can be deleted. Retained for Transmission Operator and moved to proposed TOP-002-3, Requirements R1 through R3. This is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator. Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities as per their certification as NERC registered entities. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load. EOP-002-2.1, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. TOP-002-3, R1: Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-002-3, R2: Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating

		Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1. TOP-002-3, R3: Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	Deleted	The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted. Functional Model V5: Transmission Operator: The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	Proposed TOP-003-2. Approved MOD-001-1a, Requirements R1 & R2. Approved MOD-030-2, Requirement R3.	For all but the Transmission Service Provider, moved to proposed TOP-003-2 requires the transfer of any and all required data regardless of timeframe involved. The Transmission Service Provider provisions are already covered in: • Approved MOD-001-1a, Requirement R1: Transmission Operators select transfer capability methodology from approved MOD-028, -029, or -030. • Approved MOD-030-2, Requirement R3: Transmission Operator gives transmission model updated at least once per day to Transmission Service Provider • Approved MOD-001-1a, Requirement R2: Transmission Service Providers use the methodology designated in approved MOD-001-1a, Requirement R1 by the Transmission

		Operator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. MOD-001-1a, R1. Each Transmission Operator shall select one of the methodologies1 listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. MOD-030-2, R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: MOD-001-1a, R2. Each Transmission Service Provider shall calculate ATC or AFC values as listed below using the methodology or methodologies selected by its Transmission Operator(s).
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	Proposed TOP-003-2, Requirement R5. Approved IRO-010-1a, Requirement R3.	Proposed TOP-003-2 requires the transfer of any and all required data between and amongst Balancing Authorities and Transmission Operators regardless of the timeframe involved. Data requirements for Reliability Coordinators are covered in approved IRO-010-1a, Requirement R3 making this requirement redundant for Reliability Coordinators so the Reliability Coordinator has been removed here. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator,

		Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	Approved BAL-001-0.1a. Proposed TOP-003-2, Requirement R4. Proposed TOP-002-3, Requirement R1.	The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be developing the plan and passing it down to the Balancing Authority. The Balancing Authority provides any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R5. The part of the requirement dealing with the Transmission Operator has been moved to proposed TOP-002-3, Requirement R1. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.
R6. Each Balancing Authority and Transmission Operator shall plan		The part of this requirement dealing with the Balancing Authority is replaced by approved BAL-002-

to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	Approved BAL-002-1, Requirements R2 – R4. Proposed TOP-003-2, Requirement R5. Proposed TOP-002-3, Requirement R1	0 and proposed BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R4. The part of the requirement dealing with the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. The n-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning. The SDT does not believe that there is a need for the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. As stated in the NERC Functional Model V5: " the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation." To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and BAL-002-0 (and the proposed BAL-002-1), Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any system

		condition. Balancing Authorities are not responsible for the operation of the transmission system. The Transmission Operator is responsible for the real-time operating reliability of the transmission assets under its purview, and as such has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding load, generation and interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or load shedding). If the Balancing Authorities' actions do not resolve the transmission issues, it is the Transmission Operators' or Reliability Coordinators' responsibility to direct alternative actions. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: BAL-002-1, R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. BAL-002-1, R4. Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. FAC-010-2.1, Purpose: To ensure that System

		Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-011-2, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-014-2, Purpose. To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	Approved BAL-002-1, Requirement R2. Proposed TOP-002-3, Requirement R1.	The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-1, Requirement R2 and therefore this requirement is redundant and can be deleted as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and are replaced by proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations since any deliverability problems will appear as limit violations

		in the analysis. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirement R1. Proposed TOP-002-3, Requirement R1	The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted as all elements of the requirement are now covered in other standards. Voltage and reactive power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is replaced by proposed TOP-002-3, Requirement R1 since any deliverability problems will appear as limit violations in the analysis. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

		TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	Approved INT-003-2, Requirement R1.	Replaced by approved INT-003-2, R1. INT-003-2, R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Deleted for Balancing Authority. Proposed TOP-002-3, Requirements R1 & R2.	Balancing Authority - The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority. SOLs and IROLs are limits for which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between loads and resources in real time within its Balancing Authority Area by keeping its actual interchange equal to its scheduled interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the bulk power system information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. Transmission Operator – replaced by proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs). TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions.

		TOP-002-3, R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	Approved FAC-011-2. Approved FAC-014-2. Proposed TOP-002-3, Requirements R1 & R3.	First sentence – Replaced by FAC-011-2 and FAC-014-2 where SOLs are determined. FAC-011-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-014-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. Second sentence – Replaced by approved FAC-014-2, R2 & R5.1. FAC-014-2, R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2, R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. Third sentence – Replaced by proposed TOP-002-3. 'update… as necessary' is ambiguous and the SDT believes that proposed TOP-002-3 is a better solution.

		TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-002-3, R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Approved MOD-028-1, Requirement R6.1. Approved MOD-029-1a, Requirement R3. Approved MOD-30-2 Requirement R2.4.	Replaced by approved MOD-028-1, Requirement R6.1, MOD-029-1a, Requirement R3, and MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. MOD-028-1, R6.1,Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing load within the source Balancing Authority area and decreasing generation and/or increasing load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's system, or A SOL is reached on any other adjacent system in the Transmission model that is not on the study path and the distribution factor is 5% or greater. MOD-029-1a, R3,Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. MOD-030-2, R2.4, Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will

		respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	Proposed MOD-25-2, Requirement R1 Proposed TOP-003-2, Requirement R5	Replaced by proposed MOD-025-2, R1. MOD-025-2, R1: Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the data is recorded to its Transmission Planner. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to: 14.1 - Changes in real and reactive output capabilities. (Retired August 1, 2007) 14.2 - Changes in real output capabilities. (Effective August 1, 2007) 14.3 - Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing

Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).		Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: 16.1 - Changes in transmission facility status. 16.2 - Changes in transmission facility rating	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	Deleted	This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. This is an administrative item as seen in the measure which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer	Deleted	This is part of an entity's certification and is no longer required in standards. Furthermore, accuracy is a relative term that would be difficult to measure and

models utilized for analyzing and planning system operations.		assess compliance with. What is accurate? All calculated line flows are within 5% of actual flows? What if 14,999 lines out of 15,000 had calculated line flows within 5% and the 15,000th had a 6% error? Do we now call the model inaccurate and not rely on the results? How do you even define actual flows when meters have accuracy errors as well (i.e. no perfect meter exists)?
Standard TOP-003-1 — Planned Outage Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Generator Operators and Transmission Operators shall provide planned outage information. 1.1 - Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. 1.2 - Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.	Proposed TOP-003-2, Requirements R1 & R2	Replaced by proposed TOP-003-2, Requirements R1 & R2. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its required Real-time monitoring.

1.3 - Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.		
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R1 Proposed TOP-003-2, Requirement R4	Replaced by: proposed TOP-001-2, Requirement R5 which requires the Transmission Operator to coordinate actions while proposed TOP-003-2, Requirement R1 requires the Transmission Operator to identify the data it needs from the Balancing Authority to coordinate outages of voltage regulation equipment. Further, proposed TOP-003-2, Requirement R4 requires the Balancing Authority to provide the data to the Transmission Operator that the Transmission Operator identified it needs. TOP-001-2, R5: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-003-2, R1: Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R4: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall satisfy the obligations of the documented specifications for data.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled	Proposed TOP-001-2, Requirement R6	Moved to proposed TOP-001-2, Requirement R6 TOP-001-2, R6. Each Balancing Authority and Transmission Operator shall notify the Reliability

outages of telemetering and control equipment and associated communication channels between the affected areas.		Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	Proposed IRO-001-3, R2 Proposed IRO-005-4, R1	Moved to the proposed IRO-001-3, Requirements R3 and proposed IRO-005-4, Requirement R1 which gives the Reliability Coordinator the authority to resolve the conflict. IRO-001-3, R2: Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-005-4, R1: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.
Standard TOP-004-2 — Transmission Operations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL)

		identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	Proposed TOP-001-2, Requirements R7and R9	Moved to proposed TOP-001-2, Requirements R7and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. These requirements are not limited by single or multiple Contingencies but are based solely on identified IROLs (and selected SOLs) regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator. FAC-011-02 and FAC-014-2 work collectively to establish how multiple contingencies are considered in IROLs and SOLs. FAC-014-2, R6 requires the Planning Coordinator to identify the subset of multiple contingencies from TPL-003 which result in stability limits and to provide this list to the Reliability Coordinators. FAC-011-2, R3.3 requires the Reliability Coordinator to include in their SOL methodology a process for determining which of the stability limits associated with multiple contingencies are used to establish SOLs. FAC-014-2, R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. FAC-014-2, R1 requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its

		Reliability Coordinator Area while FAC-014-2, R2 also requires the TOP to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. FAC-011-2, R1, The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs. FAC-011-2, R3, The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.3. A process for determining which of the stability limits associated with the list of multiple contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies. FAC-014-2, R1, The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. FAC-014-2, R2, The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.

		FAC-014-2 R6, The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1. The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2. If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator. TOP-001-2, R7: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	Proposed TOP-001-2, Requirements R7 and R9 Approved EOP-006-2	The SDT has determined a better way to handle such a situation is to treat it like an IROL or restoration scenario and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is replaced by proposed TOP-001-2, Requirements R7 and R9 and the approved EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power system. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.

		TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. EOP-006-2, Purpose: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	Deleted	The Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, thus this requirement is a moot point under the Functional Model definitions and can be deleted.
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: 6.1 - Monitoring and controlling voltage levels and real and reactive power flows. 6.2 - Switching transmission elements. 6.3 - Planned outages of transmission elements. 6.4 - Responding to IROL and SOL violations.	Proposed TOP-001-2 Approved VAR-001-1, Requirement R1 Proposed TOP-001-2, Requirements R7 and R9 ProposedTOP-001-2, Requirement R5 Proposed TOP-001-2, Requirement R11	The first sentence has been superseded by the NERC Reliability Standards taken as a whole. Examples of such would be the proposed TOP-001-2. The second sentence was replaced as follows: R6.1 is duplicative of approved VAR-001-1, Requirement R1 for reactive. Real power flows are covered in proposed TOP-001-2, Requirements R7 and R9. R6.2 is covered in proposed TOP-001-2, Requirement R5 R6.3 – moved to proposedTOP-001-2, Requirement R5 R6.4 – moved to proposed TOP-001-2, Requirement R11. TOP-001-2, Purpose: To prevent instability,

		uncontrolled separation, or cascading outages that adversely impact the reliability of the interconnection by ensuring prompt action to prevent or mitigate such occurrences VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard TOP-005-1 — Operational Reliability Information		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment

R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area. 1.1 - Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data**"** and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.	Approved IRO-010-1a, Requirement R3	Moved to approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Deleted	Confidentiality is not a reliability issue but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.
R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data,**"** unless otherwise agreed to by the	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.		
R4. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted	Deleted as redundant to NAESB standard –All operating data that a Purchasing Selling Entity has that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.
Standard TOP-006-1 – Monitoring System Conditions		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. 1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. 1.2 - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	R1 & R1.1 are replaced by proposed TOP-003-2, Requirement R1. R1.2 – replaced by approved IRO-010-1a, Requirement R3. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3. Approved BAL-005-0.1b.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational

	Proposed TOP-001-2, Requirement R10. Approved IRO-008-1, Requirement R2.	Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The act of monitoring is un-measureable. Entities will be in violation of other standards if they don't perform adequate monitoring. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs, and approved IRO-008-1, Requirement R2 for Real-time assessments every 30 minutes for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages.
R4. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to

		prevent instability, uncontrolled separation, and cascading outages.
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	Deleted	Deleted as this is covered in the certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs; approved IRO-008-1, Requirement R2 for real-time assessments every 30 minutes for Reliability Coordinators BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R7 for Transmission Operator avoiding IROLs. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the

		Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, Requirement R2 for Transmission Operator avoiding underfrequency; approved EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. EOP-003-1, R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions. EOP-006-2, R8. The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization.

Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in New Standard or Comment**
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.	Proposed TOP-001-2, Requirement R10	Moved to proposed TOP-001-2, Requirement R10. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	Proposed TOP-001-2, Requirement R11	Moved to proposed TOP-001-2, Requirement R11. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8 within 30 minutes.
R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	Approved EOP-003-1, Requirements R1 and in proposed EOP-003-2, Requirement R1	Replaced by approved EOP-003-1, Requirements R1. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	Approved IRO-008-1, Requirement R3	Replaced by approved IRO-008-1, Requirement R3. IRO-008-1, R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.

Standard TOP-008-1 - Response to Transmission Limit Violations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to	Approved EOP-003-1,	Replaced by approved EOP-003-1, Requirements R1 and proposed TOP-001-2, Requirement R11.

an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	Requirements R1 and in proposed EOP-003-2, Requirement R1 Proposed TOP-001-2, Requirement R11	EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	Proposed TOP-001-2, Requirements R7 and R9 Approved IRO-009-1, Requirement R5	First sentence – Replaced by proposed TOP-001-2, Requirements R7 and R9. Second sentence – Replaced by approved IRO-009-1, Requirement R5 for the Reliability Coordinator who is now responsible for such matters. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. IRO-009-1, R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is	Deleted	Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other Reliability Standards where disconnection is dependent on

endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.		System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	Proposed TOP-003-2, Requirement R1 Proposed TOP-002-3, Requirement R1 Proposed TOP-001-2, Requirement R7 Proposed TOP-001-2, Requirement R11	Data piece is replaced by proposed TOP-003-2, Requirement R1. Analysis tools are covered in the certification process for core capabilities and therefore are not needed here. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Replaced by proposed TOP-002-3, Requirement R1 for analysis. Replaced by proposed TOP-001-2, Requirement R7 for real-time analysis required for IROL mitigation. Proposed TOP-001-2, Requirement R11 covers mitigation of limit violations. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within

		the IROL's T_v, or of an SOL identified in Requirement R8.
Standard PER-001-0 - Operating Personnel Responsibility and Authority		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.	Deleted	In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted. FERC Order 693a, paragraph 112: In response to Avista, the Commission clarifies that a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a reliability coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control given the current, mandatory mechanism.
Standard PRC-001-1 – System Protection Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, and

		Transmission Owner receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

Standards Announcement

Project 2007-03 Real-time Operations

Non-binding Poll Windows Extended Through 8 p.m. Eastern on Wednesday, January 18, 2012

BALLOT WINDOWS for Three Standards STILL CLOSE at 8 p.m. Eastern on January 12, 2012

Three non-binding polls of the VRFs and VSLs associated with the following standards have been extended through 8 p.m. Eastern on Wednesday, January 18, 2012 (previously the window was to have closed Thursday, January 12, 2012):

- TOP-001-2 Coordination of Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Due to a technical issue, the non-binding polls were not visible to some ballot pool members, so the non-binding poll windows are being extended to provide all ballot pool members a full 10-day window to cast their opinions on the VRFs and VSLs associated with the three standards.

PLEASE NOTE: The three successive ballot windows are NOT being extended and will be closing at **8 p.m. Eastern on Thursday, January 12, 2012 as previously announced. The extension only applies to the non-binding polls of VRFs and VSLs.**

Instructions for Casting Opinions in Non-binding Polls

Members of the ballot pools associated with this project may log in and submit their votes for the standards and opinions for the non-binding polls from the following page: **https://standards.nerc.net/CurrentBallots.aspx**.

Link to Ballot Announcement

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

Standards Announcement

Project 2007-03 Real-time Operations

Three Ballot Windows and Three Non-binding Poll Windows Now Open Through 8 p.m. Eastern on Thursday, January 12, 2012

Now Available

Three successive ballots of the following standards, and three non-binding polls of the associated VRFs and VSLs, are open through 8 p.m. Eastern on Thursday, January 12, 2012:

- TOP-001-2 Coordination of Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Clean and redline versions of these standards and the associated implementation plan and VRFs and VSLs, are posted on the project webpage. Note that TOP-001-2, TOP-002-3, and TOP-3-2 reflect the merging of the following standards into the three proposed TOP standards, making it impractical to post a "redline" of the three proposed standards that shows the changes to the last approved versions of these standards. The last approved versions of the standards listed below have been posted on the project's web page for easy reference, and a mapping document has been posted so stakeholders can see whether the drafting team proposed retiring, revising or moving each requirement in the following standards into one of the proposed TOP standards.

- PER-001-0 Operating Personnel Responsibility and Authority
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting SOL and IROL Violations
- TOP-008-1 Response to Transmission Violations

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards and opinions for the non-binding polls from the following page:
https://standards.nerc.net/CurrentBallots.aspx

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Thursday, January 12, 2012**. Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Special Instructions for Submitting Comments with a Ballot or Non-binding Poll

Please note that comments submitted during the formal comment period, the ballots for the standards, and the non-binding polls of VRFs and VSLs all use the same electronic form, and will be compiled into a single report with duplicate comments submitted by the same entity removed and duplicate comments submitted by multiple entities consolidated. **Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form.**

Next Steps

The drafting team will consider all comments submitted during this formal comment and ballot period to determine whether to make additional revisions to the standards.

Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives. Additional information is available on the project page.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-03 Real-Time Transmission Operations
Formal Comment Period Open Dec. 14, 2011 – Jan. 12, 2012
Three Successive Ballot Windows Jan. 3 – 12, 2012

Available Now

The Real-time Operations Standards Drafting Team has made revisions to three standards and their associated implementation plan in response to stakeholder comments and a quality review:

- TOP-001-2 Coordination of Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Clean and redline versions of these standards, the associated implementation plan, and the VRFs and VSLs are posted for a formal 30-day comment period through 8 p.m. Eastern on Thursday, January 12, 2012.

Note that TOP-001-2, TOP-002-3, and TOP-3-2 reflect the merging of the following standards into a single standard, making it impractical to post a "redline" of the three proposed standards that shows the changes to the last balloted versions of these standards. The last approved versions of the standards listed below have been posted on the project's web page for easy reference.

- PER-001-0 Operating Personnel Responsibility and Authority
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting Sol and IROL Violations
- TOP-008-1 Response to Transmission Violations

Instructions for Submitting Comments

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted with ballots will use the same form, and it is NOT necessary for ballot pool members to submit two separate sets of comments (one during the comment period and a second with a ballot). Comments submitted with ballots are extremely valuable to help the drafting team revise its work. However, in an effort to reduce the burden on stakeholders providing comments, the drafting team requests that all comments (both those submitted with a ballot and those submitted by stakeholders not balloting) be submitted through the electronic form. This will ensure that stakeholders only provide a single set of comments. Further instructions will be provided in the announcement that the ballot window is open.

Next Steps

Three individual successive ballots (one for each standard) will be conducted beginning on Tuesday, January 3, 2012 and ending at 8 p.m. on Thursday, January 12, 2012. The ballot pool formed for the initial ballot of the three standards will be cloned to create three separate ballot pools, and all members of the original ballot pool will automatically be eligible to vote in the three individual ballots.

The standards are being balloted individually to provide stakeholders an opportunity to cast separate ballots for each standard. The individual ballots will provide the drafting team better feedback on which standards require additional development to achieve stakeholder consensus. Stakeholders are encouraged to consider each standard on its own merits and cast individual ballots, rather than casting the same ballot for all three standards, in order to assist the drafting team with evaluating which standards require additional development to achieve consensus.

Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

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Standards Announcement

Project 2007-03 Real-time Operations

Successive Ballots and Non-binding Polls Results

Now Available

Three successive ballot windows for TOP-001-2 Coordination of Transmission Operations, TOP-002-3 Operations Planning, and TOP-003-2 Operational Reliability Data and the associated implementation plans closed on Thursday, January 12, 2012. Non-binding polls of the VRFs and VSLs associated with TOP-002-3 closed on January 18, 2012 and TOP-001-2 and TOP-003-2 closed January 19, 2012 after a one day extension.

Voting statistics for each ballots and nonbinding polls are listed below, and the Ballot Results Webpage provides a link to the detailed results.

Standard	Ballot Results	Non-binding Poll Results
TOP-001-2 Coordination of Transmission Operations	Quorum: 82.04% Approval: 59.93%	Quorum: 81.50% Supportive Opinions: 67.61%
TOP-002-3 Operations Planning	Quorum: 82.04% Approval: 77.08%	Quorum: 76.41% Supportive Opinions: 71.42%
TOP-003-2 Operational Reliability Data	Quorum: 82.04% Approval: 78.95%	Quorum: 81.50% Supportive Opinions: 70.28%

Next Steps

The drafting team will consider all comments and determine what changes to make to each of the standards, the implementation plan, and the definitions. If the drafting team makes substantive changes to a standard, a successive ballot will be conducted for that standard. If the drafting team determines that stakeholder comments can be addressed through clarifying changes that are not substantive, the team may submit the standard for recirculation ballot.

Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives. Additional information is available on the project page.

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Updated 01/19/12

Ballot Results	
Ballot Name:	Project 2007-03 RTO Successive Ballot TOP-001-2 Jan 2012_in
Ballot Period:	1/3/2012 - 1/12/2012
Ballot Type:	Initial
Total # Votes:	306
Total Ballot Pool:	373
Quorum:	**82.04 % The Quorum has been reached**
Weighted Segment Vote:	59.93 %
Ballot Results:	**The drafting team is considering comments.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	41	0.562	32	0.438	9	21
2 - Segment 2.	11	1	5	0.5	5	0.5	0	1
3 - Segment 3.	82	1	37	0.607	24	0.393	5	16
4 - Segment 4.	27	1	15	0.682	7	0.318	2	3
5 - Segment 5.	82	1	39	0.672	19	0.328	6	18
6 - Segment 6.	47	1	24	0.632	14	0.368	3	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	3	0.3	2	0.2	1	2
9 - Segment 9.	4	0.4	2	0.2	2	0.2	0	0
10 - Segment 10.	9	0.7	4	0.4	3	0.3	2	0
Totals	**373**	**7.6**	**170**	**4.555**	**108**	**3.045**	**28**	**67**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	View
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	View
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	View

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Negative	View
1	FirstEnergy Energy Delivery	Robert Martinko		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Abstain	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Negative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill	Abstain	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Negative	View
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	View
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	Muscatine Power & Water	Tim Reed	Negative	
1	National Grid	Saurabh Saksena	Negative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	
1	New York Power Authority	Arnold J. Schuff	Negative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	View

1	Potomac Electric Power Co.	David Thorne	Abstain	View
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.	Negative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	View
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Negative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Negative	View
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Negative	View
2	Electric Reliability Council of Texas, Inc.	Charles B Manning		
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Affirmative	View
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Negative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	View
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	View
3	City Water, Light & Power of Springfield	Roger Powers	Negative	
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Constellation Energy	CJ Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Negative	View
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Negative	View
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Negative	View
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	View
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	View
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	View
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey	Negative	
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	View
4	City Utilities of Springfield, Missouri	John Allen	Negative	View

4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	View
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Negative	View
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	View
4	Imperial Irrigation District	Diana U Torres	Negative	View
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin		
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul A Cummings	Affirmative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	View
5	City of Tallahassee	Brian Horton	Affirmative	View
5	Cleco Power	Stephanie Huffman	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling	Affirmative	
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	View
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	View
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	View
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon		
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Negative	View
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	View
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Negative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Redding	Marvin Briggs	Affirmative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	View
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Negative	View
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View

6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	View
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	View
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		Edward C Stein	Affirmative	
8		Roger C Zaklukiewicz	Negative	View
8		Merle Ashton		
8		James A Maenner		
8	INTELLIBIND	Kevin Conway	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Negative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	View
10	Southwest Power Pool RE	Stacy Dochoda	Negative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Updated 01/19/12

Ballot Results	
Ballot Name:	Project 2007-03 Successive Ballot TOP-002-3 Jan 2012_in
Ballot Period:	1/3/2012 - 1/12/2012
Ballot Type:	Initial
Total # Votes:	306
Total Ballot Pool:	373
Quorum:	**82.04 % The Quorum has been reached**
Weighted Segment Vote:	77.08 %
Ballot Results:	**The drafting team is considering comments.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	53	0.707	22	0.293	7	21
2 - Segment 2.	11	1	7	0.7	3	0.3	0	1
3 - Segment 3.	82	1	46	0.719	18	0.281	2	16
4 - Segment 4.	27	1	17	0.773	5	0.227	2	3
5 - Segment 5.	82	1	46	0.793	12	0.207	6	18
6 - Segment 6.	47	1	30	0.789	8	0.211	3	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.4	4	0.4	0	0	2	2
9 - Segment 9.	4	0.4	3	0.3	1	0.1	0	0
10 - Segment 10.	9	0.7	6	0.6	1	0.1	2	0
Totals	**373**	**7.5**	**212**	**5.781**	**70**	**1.719**	**24**	**67**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	View
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	View
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	View

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Negative	View
1	FirstEnergy Energy Delivery	Robert Martinko		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Abstain	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Negative	View
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill	Abstain	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Negative	View
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	View
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	View
1	Muscatine Power & Water	Tim Reed	Negative	
1	National Grid	Saurabh Saksena	Affirmative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	View
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	View

1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.	Negative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Negative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	View
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Negative	View
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	View
2	Electric Reliability Council of Texas, Inc.	Charles B Manning		
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Affirmative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Negative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	View
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	View
3	City Water, Light & Power of Springfield	Roger Powers	Negative	
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Constellation Energy	CJ Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Negative	View
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Negative	View
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Negative	View
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Don Horsley		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	View
3	Muscatine Power & Water	John S Bos	Affirmative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	View
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	View
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey	Negative	View
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	View
4	City Utilities of Springfield, Missouri	John Allen	Negative	View

4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Negative	View
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Negative	View
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin		
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul A Cummings	Affirmative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	View
5	City of Tallahassee	Brian Horton	Affirmative	View
5	Cleco Power	Stephanie Huffman	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling	Affirmative	
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	View
5	MidAmerican Energy Co.	Christopher Schneider	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	View
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon		
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	View
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	View
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Negative	View
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Affirmative	

6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Negative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	View
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Edward C Stein	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Merle Ashton		
8	INTELLIBIND	Kevin Conway	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Stacy Dochoda	Negative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Updated 01/19/12

Ballot Results	
Ballot Name:	Project 2007-03 Successive Ballot TOP-003-2 Jan 2012_in
Ballot Period:	1/3/2012 - 1/12/2012
Ballot Type:	Initial
Total # Votes:	306
Total Ballot Pool:	373
Quorum:	82.04 % The Quorum has been reached
Weighted Segment Vote:	78.95 %
Ballot Results:	The drafting team is considering comments.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	59	0.766	18	0.234	5	21
2 - Segment 2.	11	0.9	7	0.7	2	0.2	1	1
3 - Segment 3.	82	1	51	0.797	13	0.203	2	16
4 - Segment 4.	27	1	16	0.727	6	0.273	2	3
5 - Segment 5.	82	1	48	0.814	11	0.186	5	18
6 - Segment 6.	47	1	31	0.838	6	0.162	4	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.4	3	0.3	1	0.1	2	2
9 - Segment 9.	4	0.4	3	0.3	1	0.1	0	0
10 - Segment 10.	9	0.7	6	0.6	1	0.1	2	0
Totals	**373**	**7.4**	**224**	**5.842**	**59**	**1.558**	**23**	**67**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Negative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Negative	View
1	Arizona Public Service Co.	Robert Smith		
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	View
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	View

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Affirmative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph F Meyer	Negative	View
1	Entergy Services, Inc.	Edward J Davis	Negative	View
1	FirstEnergy Energy Delivery	Robert Martinko		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor	Negative	View
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Negative	
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	View
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	View
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	Muscatine Power & Water	Tim Reed	Negative	
1	National Grid	Saurabh Saksena	Affirmative	View
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	View

1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	View
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Negative	View
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	View
2	Electric Reliability Council of Texas, Inc.	Charles B Manning		
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Marie Knox	Affirmative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	View
2	New York Independent System Operator	Gregory Campoli	Negative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung	Affirmative	
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Negative	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	View
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Negative	
3	City of Redding	Bill Hughes	Affirmative	View
3	City Water, Light & Power of Springfield	Roger Powers	Negative	
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	CJ Ingersoll	Affirmative	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Negative	View
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Negative	View
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley		
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	View
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	View
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	View
4	City Utilities of Springfield, Missouri	John Allen	Negative	View

4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Negative	View
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	View
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette		
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	View
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin		
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul A Cummings	Affirmative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	View
5	City of Tallahassee	Brian Horton	Affirmative	View
5	Cleco Power	Stephanie Huffman	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy	James B Lewis		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Negative	View
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling	Affirmative	
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	View

5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	View
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Negative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	View
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Negative	View
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon		
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	U.S. Bureau of Reclamation	Martin Bauer		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Affirmative	View
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Abstain	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View

6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		Merle Ashton		
8		James A Maenner		
8	INTELLIBIND	Kevin Conway	Abstain	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	View
9	California Energy Commission	William M Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

Individual or group. (59 Responses)
Name (38 Responses)
Organization (38 Responses)
Group Name (21 Responses)
Lead Contact (21 Responses)
Question 1 (55 Responses)
Question 1 Comments (59 Responses)
Question 2 (52 Responses)
Question 2 Comments (59 Responses)
Question 3 (53 Responses)
Question 3 Comments (59 Responses)
Question 4 (32 Responses)
Question 4 Comments (59 Responses)
Question 5 (0 Responses)
Question 5 Comments (59 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
Requirements R1 and R2 should not be separate. Having them broken out in this manner could potentially put entities in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then Requirement R4 should be broken down into two requirements. Requirement R4 states that information is being requested, AND is available. In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning Analysis as "An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency? The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency does not occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding

TOP-001, Requirement R8: The drafting team needs to define the term “internal area reliability” in order to improve the clarity of the standard. Double jeopardy is introduced with TOP-001 R8 and FAC-014 R5.2. Fac-014 R5.2 states “The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area”; while TOP-001 R8 states “Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis.”
No
The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, suggest that the requirement should either state the requirement for a process to conduct an Operational Planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement. R1. The Transmission Operator shall CONDUCT an Operational Planning Analysis for the next day’s planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. Requirement R2 uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-014 R5. SOL’s that affect a TOP internal area would also affect the RC area. The Drafting Team needs to define the term “internal area reliability” in order to improve the clarity of the standard (see Question 1 comments regarding TOP-001 Requirement R8). Regarding Requirement R3, would notifying GO’s of “their roles” in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall?
No
TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates the TO, LSE, and Generator Owners to provide this real-time data. These entities provide a wealth of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue. TOP-003 R5 has only a severe VSL. Data providers can provide hundreds if not thousands of points to TOPs. If one RTU goes down is the data provider going to be assessed a severe VSL?
TOP-001-2 is referencing a NERC definition for “Reliability Directive” which is not in effect today and is listed on the Definitions of Terms Used in Standard Section on page 2. It is stated that the definition of “Reliability Directive” would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board” usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.” It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Individual
Jonathan Appelbaum
United Illuminating Company
No
R3 phrase “known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis” is confusing. Glossary defines emergency as Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. Glossary defines Operation Planning analysis as An analysis of the expected

system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). I do not see the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to effected by an anticipated Emergency. Those TOP's known to be effected are part of the group expected to be effected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. Along the thought the Time Horizon in the Requirement is Operations Planning. I suggest rephrasing this requirement as: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Comment for R8. It seems that double jeopardy is introduced with TOP-001 R8 and FAC-011 R5.2. Fac-011 R 5.2 states The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area; while TOP-001 R8 states R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis.
No
The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, UI suggests the requirement should either state the requirement for a process to conduct an Operational planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement. R1. The Transmission operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. R2: uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-011 R5. SOL's that affect a TOP internal area would also affect the RC area.
No
TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates TO, LSE, and Generator Owners to provide this real-time data. These entities provide a multitude of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear to UI that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.
No
TOP-003 R5 has only a severe VSL. This seems unequitable to the data providors who are responsible for tens of thousands of data points, some redundant. Especially since State Estimators are designed to estimate for bad or missing data.
Individual
Jonathan Appelbaum
United Illuminating
No
R3 phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. Glossary defines emergency as Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. Glossary defines Operation Planning analysis as An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). I do not see the difference between TOPs KNOWN to be

effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to effected by an anticipated Emergency. Those TOP's known to be effected are part of the group expected to be effected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. Along the thought the Time Horizon in the Requirement is Operations Planning. I suggest rephrasing this requirement as: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Comment for R8. It seems that double jeopardy is introduced with TOP-001 R8 and FAC-011 R5.2. Fac-011 R 5.2 states The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area; while TOP-001 R8 states R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis.
No
The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, UI suggests the requirement should either state the requirement for a process to conduct an Operational planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement. R1. The Transmission operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. R2: uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-011 R5. SOL's that affect a TOP internal area would also affect the RC area.
No
TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates TO, LSE, and Generator Owners to provide this real-time data. These entities provide a multitude of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear to UI that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.
No
TOP-003 R5 VSL is only severe. Data providers can provide hundreds if not Thousands of points to TOPs. If one RTU goes down is the data provider going to be assessed a severe VSL.
Individual
Rich Vine
California Independent System Operator
No
R6 requires Balancing Authorities and Transmission Operators to notify "negatively impacted interconnected NERC registered entities" of planned outages. This term is not specific enough to narrow down who must be notified. For instance, with this open-ended wording it could be construed that BAs would have to notify LSEs and DPs in their areas which would be an onerous task. We would recommend staying with "negatively-affected BAs and TOPs." The wording in R9 is confusing and is not specific enough to ensure compliance. In particular the requirement prohibits operation outside any SOL "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based." However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. In addition, under R9 and M9, how will the word "continuous" be defined or measured? This is extremely important to understand because the VSL table states the following as Severe for R9: "The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria." It seems that the effective date should be set much sooner than 24 months

following approval since there are basically no new requirements associated with this standard. Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Yes
The ISO supports the changes made in TOP-002-3 but notes that the "Seasonal Assessment" previously required by TOP-002-2 is no longer addressed in the TOP-002-3 wording. Is this an oversight or is this seasonal assessment going to be contained elsewhere?
Yes
The words "and Operational Planning Analyses" should be added to the end of the first sentence in R2 (the Operational Planning Analysis is included in R1). A similar addition should be made to R4.
Individual
Thomas E Washburn
FMPP
Yes
Yes
Yes
Yes
Comments for Project 2007-03 Real-Time Transmission Operations The changes to the TOP Standards are a great improvement over the existing Standards; however, I think because they are so much better than the existing Standards that they should be implemented as soon as possible. I think one year is enough time to make the necessary changes to processes, procedures and documentation. Even more important than the implementation of the new Standards is the deletion of the existing Standards as soon as possible. Some of the existing Requirements are worthless and unenforceable. The SDT has determined that some of the existing Requirements are replaced by new requirements and they will need to be enforceable until the new Requirements are enforceable. However, the SDT has identified some Requirements that are either no longer necessary or covered by existing Requirements or the Functional Model (see mapping document excerpts below): • PER-001-0 R1 • TOP-001-1 R1 • TOP-002-2 R2 • TOP-002-2 R7 • TOP-002-2 R8 • TOP-002-2 R18 • TOP-002-2 R19 Deleting these Requirements does not need to have an implementation period. They can be deleted as soon as approved by FERC with no waiting. TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it never should have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! Also the SDT has identified some Requirements that apply to the Balancing Authority that are either no longer necessary (or even NEVER should have been applicable) or covered by existing Requirements or the Functional Model (see mapping document excerpts below): • TOP-002-2 R1 • TOP-002-2 R5 • TOP-002-2 R6 • TOP-002-2 R10 The SDT states for TOP-002-2 R10: "The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority." Obvious wrong Requirements like TOP-002-2 R10 should be deleted ASAP. They are a compliance conundrum, and open to compliance fines! From the Mapping Document: PER-001-0 R1 is deleted because "In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted." TOP-001-1 R1 is deleted because "This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible

entity. These needed actions required for reliability of the bulk power system have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement." TOP-002-2 R1 is deleted for the Balancing Authority because "The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and must take action per approved EOP-002-2.1, Requirement R6 and thus the Balancing Authority part of this sentence can be deleted. Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities as per their certification as NERC registered entities. " TOP-002-2 R2 is deleted because "The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted. " TOP-002-2 R5 is deleted for the Balancing Authority because "The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model." TOP-002-2 R6 is deleted for the Balancing Authority because "The part of this requirement dealing with the Balancing Authority is replaced by approved BAL-002- 0 and proposed BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. " TOP-002-2 R7 is deleted because "The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-1, Requirement R2 and therefore this requirement is redundant and can be deleted as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority!" TOP-002-2 R8 is deleted because "The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted as all elements of the requirement are now covered in other standards. Voltage and reactive power balance are the responsibility of the Transmission Operator (not the Balancing Authority) and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority!!" TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it should never have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! TOP-002-2 R10 is deleted for the Balancing Authority because "The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority." TOP-002-2 R18 is deleted because "This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. " To make matters worse this Requirement is the tier 1 Requirements for actively monitored Requirements for 2012! Which means NERC views this as an important Requirement to reliability. But I agree with the SDT that this Requirement adds NO reliability benefit. TOP-002-2 R19 is deleted because "This is part of an entity's certification and is no longer required in standards. "
Individual
Scott Bos
Muscatine Power and Water
No
Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you can't draw SOLs into the same category as IROLs unless you clearly indicate these standards only apply to a subset.

No
Issue: The SDT uses a non FERC approved term of “Operational Planning Analysis”, This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval.
No
Issue: There is a great possibility of double jeopardy when R3 and R4 have in part the statement of “…in meeting its NERC-mandatory reliability requirements.” So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non-compliant with any of the unknown “…in meeting its NERC-mandatory reliability requirements” then they would be found non-compliant with this Standard. It is not clear why this Standard is being written with the statement of: “…in meeting its NERC-mandatory reliability requirements.”
Yes
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
No comment.
PacifiCorp would like to express their appreciation to the SDT for their efforts. This consolidation effort has resulted in a more streamlined approach to this set of interrelated NERC Reliability Standards. PacifiCorp would recommend that NERC consider other sets of standards for which such a consolidation effort would be mutually beneficial to NERC and stakeholders, from both a compliance and administrative standpoint.
Individual
Howard Rulf
We Energies
No
R3’s wording is incomplete. It requires informing and states who must be informed but does not state what must be told. The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP’s BA(s) of an Emergency. Should also include the BA informing its RC and TOP(s) R4 It is not clear what emergency assistance a TOP can provide? Most actions would involve moving a generator or shedding load, the few items a TOP can do independently like returning a line from outage, or switching reactive devices should be done as a matter of course. R5 The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP’s BA(s) of an operation resulting in an Adverse Reliability Impact. Should also include the BA informing it’s RC and TOP(s) R6 is overly broad. Every entity in an interconnect can be negatively impacted somehow. The requirement should be focused on the operational entities of the TOP, BA and RC. These are the entities that specify the data that must be made available see IRO-010, proposed TOP-003 from others. Individual asset owners provide data to the operators and when the operators plan an outage they should let the other affected TOP, BA and RC know its to happen. R8: change “have” to “has”. The associated measures should be updated to reflect the above. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.
No
How current should the Operational Planning Analysis be? By definition it can be 12 months ahead. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.

No
R1.4 and R2.4: The deadline must allow time to gather and send the data. If the TOP said immediately, you would be immediately non-compliant. In addition, R2 should include data necessary to perform at least Next Day analysis, even Operational planning Analysis. R5 needs to include the DP. Data Retention: Each bullet states that monitoring is required in accordance with Measures. Measures cannot be requirements.
Group
Southwest Power Pool Regional Entity
Emily Pennel
No
Action is only required by the proposed standards if a real time violation of a previously identified SOL occurs. No action is required in a preventative manner and no action is required as a result of a real time problem that was not identified by the Operational Planning Assessment. R5 should include notifying the RC of anticipated SOL violations. Addition in quotes. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact "or SOL violation" on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.
No
See item number 5 for comments.
Yes
Yes
The standards being proposed are not sufficient to replace the requirements of the 9 standards being retired by this project. The requirements listed below are not covered by the new standards. TOP-001-1 R5. New requirement (TOP-001-2 R11) does not cover "take actions to avoid when possible or mitigate the emergency." Pre-emptive action is an important part of preventing cascading outages. The proposed TOP-001-2 R11 only deals with real time violations. The SDT is relying upon IRO-001-3 being approved in order to retire some of these requirements; however, this has not yet been passed by industry. TOP-002-2 R1. If conditions change on the current day, where in the proposed standards is a new operating plan required to prepare for the next contingency or identify new SOLs? R6. Which of the proposed standards obligate the TOP to continuously plan for the next N-1 event? R13. MOD-024 and MOD-025 (which would replace this requirement) were not approved by FERC in the initial set of standards. A replacement standard MOD-025-2 has been posted for comment, but has not had an initial ballot. TOP-004-2 R1. The proposed TOP-001-2, R7 and R9, only requires IROLs and certain SOLs be respected. The requirement being retired applied to all SOLs. This reduces BES reliability. R4. This covers cases where no Operational Planning Assessment is available to ensure the system is in a safe state. The proposed TOP-002-3 does not include any requirement about when a new study is needed. TOP-006-2 R5., R6., R7. The SDT is relying on the certification process to justify the retirement of these requirements. However, the Certification Process only looks at approved applicable Reliability Standards. If these are retired, these will no longer be reviewed by the Certification Team. TOP-008-1 R2. The current language in TOP-008-1, R2 of "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" is different than the proposed language of TOP-001-2, R7 and R9 "shall not operate outside the IROL (or SOL)". We recommend incorporating the "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" into TOP-001-2 R7. PER-001-0 R1. The existing requirement specifically places the responsibility on the personnel on shift not on the senior management. This does not appear to be covered by any other requirement. PRC-001-1 R2. The obligation to take corrective actions for protection relay or equipment failures is not covered by the proposed TOP-003-2 standard.
Group
NIPSCO

Joe O'Brien
Yes
In R8 consider changing "internal area" to "Transmission Operator Area" In R9 consider clarifying "continuous duration", what is that?
Yes
None at this time
Yes
In R3 & R4 the phrase "in meeting its NERC-mandated reliability requirements" is too open-ended and may be difficult to comply with. This should be more specific; what requirements are these.
Yes
None at this time
None at this time,
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
• If the definition of “Reliability Directive” remains, the Definitions of Terms Used in the Standard should note that there is in fact a new or revised definition. ATC agrees with the definition. • Requirement 4 – This should have a control by the Reliability Coordinator to ensure that a Transmission Operator in distress has, in fact, implemented their “comparable emergency procedures”. • Requirement 5 - ATC does not agree with removing the BA from this requirement since they make note that it will be addressed in another, “proposed” requirement as stated in the mapping document. • Requirement 7 - Real-Time EMS representation of IROL Tv, will require an unidentifiable amount of resources. • Requirement 9 - SOL’s should have a time requirement. Also, they should not be raised to the level of IROL’s as may be insinuated by this requirement if they are discretionary, as noted in Requirement 8. • Requirement 11 - If this requirement entails the issuing of a “Reliability Directive”, it should be stated as such.
No
Requirement 1 - Granted, if the rationale does not mandate “how” an analysis is completed, a better requirement of the “what” should be stated. If this analysis base-case, N-1, is unilateral by the TOP, without iteration with the BA, then should the process be documented?
No
In the introduction to this question, the Standard number should be corrected to TOP-003-2. Requirement 1- A data specification must have bounds. There is nothing that would preclude a request for data that is not achievable yet is mandated to be satisfied by Requirement 5. Requirement 1, sub-Requirement 1.2 may never be arrived at given the former.
None
ATC feels this project has diminished a good base of existing standards, and introduced ambiguity, and vagueness. Additionally, we feel certain key aspects of the current standards were removed for example, “Clear, decision making authority” from System Operators, and the need for “Uniform Line Identifiers”, which is not in the interest of Reliability.
Individual
Jeff Longshore
Luminant Energy Company, LLC
Yes
Yes
No
TOP-003-2 as currently written does not provide any recourse for the entity receiving a data request if that entity feels the data request is unreasonable either in content or timing or if the entity does not have the data available to submit. As such I would recommend modify R5 as follows: R5. Each......shall

satisfy the obligations of the documented specification for data. R5.1. If the entity receiving the data request cannot provide the requested data either in content or timing then the entity receiving the data request shall notify the requesting entity and provide a reason for not providing the data.
No
The VSL for TOP-003-2 R5 places a more stringent severity level on the entities receiving the data requests than it places on the entities that are responsible for creating the data requests. As such, I would suggest changing the VSL for TOP-003-2 R5 to the following: Lower: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy one of the obligations of the documented specification for data. Moderate: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy two of the obligations of the documented specification for data. High: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy three of the obligations of the documented specification for data . Severe: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy four or more of the obligations of the documented specifications for data.
Group
Lincoln Electric System (LES)
Eric Ruskamp
No
R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included a provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? R8 is unclear as currently drafted. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation.
Yes
No
Please refer to comments submitted by MRO's NERC Standards Review Forum for LES' concerns related to TOP-003.
No
The word "affected" should be added to the Moderate VSL for TOP-001-2 R3 following "…known or expected to be affected by an actual…".
Group
Progress Energy
Jim Eckelkamp
No
Progress, while supporting what we believe is the overall intent of this Standard revision, cannot support an affirmative vote on TOP-001-2. Progress appreciates the efforts of the SDT and offers the following suggestions: In R8 it remains unclear what is meant by the phrase "supporting its internal area reliability." Clarity and unambiguous language is needed here so that entities can clearly understand and comply with the requirement. Progress understands from reading the most current

“Consideration of Comments” that the Standard Drafting Team left this phrase intentionally undefined; however, the inclusion of this phrase means that in an audit scenario there could be a disagreement about what “supporting its internal area reliability” means. This has the potential to negatively impact the compliance position of the Transmission Operator. In R9 it is unclear what is meant by a “continuous duration that would cause a violation…” Some entities may have facility ratings that are time based, while other entities take the position that the exceedance of a facility rating for any amount of time means an SOL violation. A suggested change in wording would be to simplify the requirement to read “Each Transmission Operator shall not operate outside any SOL indentified in Requirement R8 that would cause a violation of the Facility Rating or Stability criteria upon which it is based.” Progress suggests changing R10 to read “Each Transmission Operator shall inform its Reliability Coordinator of the mitigation actions it has taken or directed to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded.” The current draft language implies that the TOP must only inform the RC of “…its actions…” Progress suggests switching the order of the current R10 and R11; from reading the most current “Consideration of Comments” it seems that the actions required in R8-R11 are intended to be sequential. Progress suggests that switching the order of the current R10 and R11 would make it easier for a reader to understand that these are intended to be sequential actions.
Yes
A definition of "internal area reliability" is needed
Yes
Please include "operational Planning Analyses" in R2 as you have in R1.
Group
Bonneville Power Administration
Annie Lauterbach
No
Comments: Given the potential uncertainty regarding the 30 Minute Rule, BPA suggests adding more clarity to the standard TOP-001-2 as the new draft could be interpreted to mean that one would need to get the flows below the SOL immediately. BPA believes this is not practical because it takes a definite amount of time to change schedules, move generation, or perform other actions in order to reduce loadings on facilities. BPA believes the new draft should include guidance as to how much time the BA or Transmission Operator would be allowed in order to reduce flows when there is an SOL violation. BPA suggests that more clarity be provided and/or the 30 minute rule be added back to the standard.
No
Given the potential uncertainty regarding how many day ahead studies may be required, BPA suggests adding more clarity to the standard TOP-002-3. BPA recognizes that various regions experience peak operations at different times of the day, anticipated generation patterns shift over the course of the day, and transmission facilities come in and out of service for planned work at various times throughout the day. Hence, due to these multiple shifts in forecast system conditions, it is unclear whether more than one study is required to meet the requirements of this standard.
Yes
BPA is in support of standard TOP-003-1, due to the importance of being able to receive data.
Individual
DAVID DOCKERY
Associated Electric Cooperative, Inc.
Yes
R3 Guidance Add: A Guidance Section for Requirement R3 clarifying “anticipated Emergency” - AECI believes the SDT should draft guidelines as to what “anticipated Emergency” means within this requirement. That guidance should also caution against dumping information (data-overload)upon

neighboring parties, for trivial impacts to their system. Rationale: In earnest to avoid non-compliance with R3, entities could blast their neighbors with all changes, regardless of impact, and then the purpose of this requirement will be lost.) R6 Requirement wording Change: “negatively impacted” To: “known negatively impacted” Rationale: While 1st hand affected parties are likely known, secondarily affected parties might pose a compliance problem. R8 Guidance Add: An R8 Guidance section Rationale: AECI’s understanding is that our providing our RC with AECI’s most-limited-element equipment seasonal operating limits and short-term limits, where applicable, meets this requirement. If we are wrong, then additional guidance is definitely necessary.
Yes
R1 Rationale Change: Rework or remove entirely Rationale: The R1 Rationale section does not match the R1 requirement as currently worded, and frankly is impossible, within the timing constraints of next-day analysis. (Example: PSS/E is technically a tool for steady-state network analysis. Without that tool, or a similar network-analysis tool being available, such analysis would be impossible by hand.) R3 Requirement wording Change: “in the plan(s)” To: “in the N-1 contingency-related plan(s)” Then Append: “, N-2 related contingency-plan(s) should be omitted unless highly plausible.” Rationale: This recommended change seeks to avoid information overload on neighbors, while still encouraging more in-depth near-term contingency planning.
Yes
TOP-003-1 R1, R2, and R3 Guidelines Add: Guidelines Section - These requirements are all written as highly TOP-centric and BA-centric, without regard to the confusion and work-load a single published plan could cause small entities. If hundreds or perhaps thousands of data-points are cited within a uniformly circulated plan, yet some entities provide only one or two obscure points within that plan, then the TOP or BA is being unnecessarily inconsiderate, and should have appropriately filtered that request for their audience. Rationale: Very large TOPs or BAs would benefit from being reminded that they need to consider their audience when sending out plans as data-requests to small entities. There is no need to overwhelm smaller entities with a lot of unrelated data, or data that does not seem to match their own identifiers. We can do better.
No
TOP-001-2-R1 VSL Change: “unless such action would violate” To: “and such action would have violated” Rationale: State the issue rather than recite the requirement. TOP-001-2-R8 VSL Change: “whichever is less” To: “whichever is greater” Rationale: Intent TOP-001-2-R10 VSL Change: “has been” To: “had been” Rationale: grammatical TOP-002-3-R1 Lower VSL: Duplicate Severe VSL wording then append “, on one day within a calendar year.” TOP-002-3-R1 Moderate VSL: Duplicate Severe VSL wording then append “, on two non-consecutive days within a calendar year.” TOP-002-3-R1 High VSL: Duplicate Severe VSL wording then append “, on three non-consecutive days or two consecutive days within a calendar year” TOP-002-3-R1 Severe VSL: Append: “, on four or more days, or three consecutive days within a calendar year.” TOP-002-3-R1 VSL changes Rationale: Eliminate zero-defect expectation TOP-002-3-R3 VSL Change: “of the NERC” To: “, whichever is greater, of the NERC” Rationale: precision and alignment with wording in TOP-01-2 R8 VSLs.
Group
ISO/RTO Standards Review Committee
Albert DiCaprio
No
Instead of using ‘its’ TOP in R1 we suggest using ‘a’ TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn’t identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by ‘internal area reliability’? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren’t these requirements now in conflict with the purpose of the standard which is directed toward impacts on the

reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
No
Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Yes
No
TOP-001-2, R3 Moderate VSL – the word "affected' has been omitted and needs to be inserted. TOP-003-2, R1 & R2 – The use of the term 'element' in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 – The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn't this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
We assess that the industry's comment on R3 regarding the need to inform all NERC registered entities identified in the plan(s) was due to the absence of a requirement to identify these entities. We therefore suggest to revise Requirement R2 to drive home the need to identify registered entities that are included in the plan(s) to operate to within IROL and SOL, and set the stage for R3: Each Transmission Operator shall develop a plan, and identify the entities that will be required to implement actions, to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
Yes
We agree with the addition of R2, but have a concern over Measure M2, which says: M2: Each Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R2. The wording "dated, current, in force" does not reflect what's in the requirement R2, and is not necessary. This wording pertains to the data retention requirement, which is already included in the second bullet in Section D, 1.3 – Data Retention: "Each Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit." We suggest to remove this wording from M2.
Yes

Group
FirstEnergy
Sam Ciccone
Yes
Yes
Yes
Yes
FE has the following comments and suggestions: 1. In the mapping document, it shows that PRC-001-1 R2 will be replaced by the new TOP-003-2 R5. However, we do not see a new version of PRC-001-2 posted. Also, the implementation plan makes no reference to PRC-001. 2. The mapping document does not seem to be referencing the correct version of TOP-005 (should be Version 2a). Also, the mapping document is not referencing the correct requirement for TOP-006-1 R4 (the RC should not be shown as applicable).
Individual
Robert Roddy
Dairyland Power Cooperative
Yes
Concern re R5. The determination of when an operating condition could be "expected to result in an Adverse Reliability Impact" would be difficult and ambiguous.
Yes
No
R1 and R2 refer to "A periodicity for providing data" and "The deadline by which the respondent is to provide the indicated data". What if this specification is unreasonable? To address this concern, DPC suggests adding the words "mutually agreeable" as was used in reference to the format specification.
Yes
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
No
R2 - This requirement requires the BA, GOP, and LSE to notify the TOP if it cannot comply with the Reliability Directive. (Comment) – Should include the language that the entity is not able to comply with the Reliability Directive due to violation of safety, equipment regulatory or statutory requirements. R7 – This requirement requires that the TOP not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL (Comment) – Should the language in the requirement also include the reference to SOLs since WECC does not have IROLs? R8 – This requirement requires the TOP to inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis (Comment) – Remove “which, while not IROL” from the requirement language and add “that” before “have been identified”. This would make the statement more clear. R9 – This requirement requires that the TOP not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. (Comment) – Define Continuous. What would constitute a violation? 5 minutes, 10 minutes? In some cases corrective action requires participation and/or direction from the Reliability Coordinator and this could take up to 30 minutes. Recommend leaving the 30 minute duration in

place. (Comment) – Recommend referencing R7 if the SOLs are included in the requirement. R10 – This requirement requires the TOP to inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. (Comment) – the language should include the reference to R7 if the SOL is included in the requirement. (Comment) – Recommend including time frame for notification to the Reliability Coordinator to include "30 minutes or less" R11 – This requirement requires the TOP to act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Measures or of an SOL identified in Requirement R8. (Comment) – Since only the Reliability Coordinator has the authority to direct others to take action; should the language be revised in the following manner; "The TOP shall take action to mitigate both the magnitude and duration of exceeding an IROL or an SOL as identified in R7 and R8 that occur within its TOPs area. The TOP shall appeal to the Reliability Coordinator to direct other TOPs in mitigating both magnitude and duration on interconnected facilities on the Bulk electric System".
No
R1 – This requirement requires the Transmission Operator to have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions (Comment) - Recommendation that the requirement language be changed to "Each TOP shall perform the required Operational Planning Analysis for Next-Day Operations to assess if the Next-Day Operations Plan will exceed any of its Facility and/or stability limits under normal or emergency conditions". R2 – This requirement requires the Transmission Operator to develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 (Comment) Recommend that the language be revised for clarity to state the following; "The TOP shall develop a plan to operate within established IROL and SOLs according to the Operation Planning Analysis performed for its Next-Day Operation in Requirement 1. R3 – This requirement requires the TOP to notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) (Comment) – Recommend revising the language in the requirement to state the following; "The TOP shall notify all affected NERC Registered entities of possible impacts identified in its Operational Planning Analysis for its Next-Day Operations in Requirement 1. M2 – The measurement requires the TOP to have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement (Comment) – Revise the Measurement to state the following; "The TOP shall have evidence that it developed a plan to operate within established IROL or SOLs supporting its internal reliability area as a result of its Operational Planning Analysis performed". M3 – Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records. (Comment) – Revise the measurement to sate the following; "The TOP shall provide evidence that it notified affected NERC Registered Entities as being impacted in the Operational Planning Analysis related to its Next-Day plan. Such evidence shall include but not be limited to dated E-Mails, Operator Logs, or Voice Recordings. Data Retention – Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records. (Comment): The time frames appear to be pretty specific for the data retention. However when will the entity know that it has to save the evidence farther back than the set time frame. Would it not be better to have the Data Retention language require the entity to save all evidence back 12 months and to save any evidence related to a system disturbance/event?
Yes

Yes
None
Individual
Kathleen Goodman
ISO New England Inc.
No
Instead of using ‘its’ TOP in R1 we suggest using ‘a’ TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn’t identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by ‘internal area reliability’? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren’t these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who’s responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using ‘its’ RC in R6 rather than ‘the’ RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
No
Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase ‘within its TOP Area or for which it has been notified by another TOP under R3’ in R1 immediately following (IROL).
Yes
The definition of Reliability Directive is contained in COM-002-3 and that standard hasn’t been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
No
Instead of using ‘its’ TOP in R1 we suggest using ‘a’ TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn’t identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by ‘internal area reliability’? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren’t these

requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
No
Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Yes
No
TOP-001-2, R3 Moderate VSL – the word "affected' has been omitted and needs to be inserted. TOP-003-2, R1 & R2 – The use of the term 'element' in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 – The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn't this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then they should break out R4 into two requirements. Who's to say that the information is requested AND available? In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is

permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard.
No
Comments: In Requirement R2 the Drafting Team needs to define the term "internal area reliability" in order to improve the clarity of the standard. Regarding Requirement R3: Would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall? Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.
Comments: TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for "Reliability Directive" changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an "across the board" usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts." It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP - Occidental Chemical Corporation
Yes
From the GO/GOP perspective, Ingleside Cogeneration LP believes that the SDT has captured the appropriate circumstances for when a Reliability Directive is issued and identified – and the circumstances under which it may be not be possible to accommodate one.
Yes
Yes
Although we would prefer to see a consolidated RC-BA-TOP data specification, Ingleside Cogeneration LP agrees that TOP-003-1 is a good first step in that direction. Any help the SDT can provide to reduce overlap in data requests and to drive to a common format is appreciated.
Yes
Ingleside Cogeneration LP believes that the requirements applicable to a GO/GOP carry VRFs, VSLs, and Time Horizons consistent with those assigned to similar requirements.
Individual
David Thorne

Pepco Holdings Inc
No
PHI supports the comments provided by the ISO/RTO Standards Review Committee.
No
PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Yes
No
PHI supports the comments provided by the ISO/RTO Standards Review Committee.
PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Group
Dominion
Connie Lowe
Yes
Yes
No
If this question was meant to refer to TOP-003-2, then Dominion offers the following comments: M5 reads "Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities." Since R2 was added, Dominion suggest M5 should read as "receiving a data specification in Requirement R3 or R4 shall make available evidence that is has satisfied the obligations of the documented specifications for data in accordance with Requirement R5....".
Yes
Page 1 and Page 15 of the Violation Risk Factor and Violation Severity Level Assignments document, titles reads; Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-2, TOP-003-2:, Dominion suggests changing TOP-002-2 to TOP-002-3.
Individual
Mahmood Safi
Omaha Publc Power District
No
OPPD is concerned with Requirements (R8 and R9) related to System Operating Limits (SOLs). We would like to ask the SDT to clarify what the word "continuous duration" means in terms of timing. We understand the "continuous duration" is based on Facility Rating or Stability criteria, however, without any defined time frame, the term "duration" would be subject to variety of interpretations. OPPD supports a time window to allow TOP to return from SOL similar to IROL Tv.
Yes
No
OPPD is requesting clarification on operational data requirements (R1 and R3) related to "documented specification for the data necessary for it to perform…" What the document should include that is specifying operational data request from or to other Transmission Operators. Additionally, how often operational data specification document should be provided/updated to or from other Transmission Operators.
Yes

Individual
David Burke
Orange and Rockland Utilities, Inc.
No
Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then they should break out R4 into two requirements. Who's to say that the information is requested AND available? In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard.
No
Regarding Requirement R3: Would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall? Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.
Comments: TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this

standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board” usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.” It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Individual
Joe Petaski
Manitoba Hydro
No
-R1 - Manitoba Hydro suggests that the first instance of ‘identified’ in R1 be removed as it is redundant given that R1 already specifies that the Reliability Directive is ‘identified as such’. As drafted, the standard suggests that there is a difference between an ‘identified Reliability Directive’ and a ‘Reliability Directive’. -Data Retention (1.3) – The data retention requirements are too uncertain for two reasons. First, the requirement to “provide other evidence” if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what ‘other evidence’, besides the specified logs, recordings and emails, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. This comment applies to TOP-001-2, TOP-002-3, and TOP-003-1.
No
-R1 - Given that an Operational Planning Analysis is itself an assessment of planned operations (i.e. the definition of Operational Planning Analysis is ‘An analysis of the expected system conditions for the next day’s operation…’) it is unnecessary to state that the Operational Planning Analysis must allow an assessment of planned operations. Accordingly, Manitoba Hydro suggests that the phrase '…that will allow it to assess…’ be replaced with “assessing”.
No
-M1 – This measure goes beyond the requirements of the standard, as there is no requirement for a specification document to be dated. Manitoba Hydro suggests either striking ‘dated’ from M1 or adding the requirement to have a ‘dated documented specification’ to R1. -M2 – Same comment as M1. Manitoba Hydro suggests either striking ‘dated’ from M2 or adding the requirement to have a ‘dated documented specification’ to R2. A -R3 - For consistency with R1 and overall clarity, Manitoba Hydro suggests changing the wording of R3 to ‘Each Transmission Operator shall distribute its documented specification developed in accordance with R1 to those entities that have data required by the Transmission Operator to support its Operational Planning Analysis and Real-time monitoring ’. The VSL for R3 should be changed accordingly as well. -R4 - For consistency with R2 and overall clarity, Manitoba Hydro suggests changing the wording of R4 to ‘Each Balancing Authority shall distribute its documented specification developed in accordance with R2 to those entities that have data required by the Balancing Authority to perform its Real-time monitoring’. The VSL for R4 should be changed accordingly as well.
No
-TOP-002-3 R3 VSL - The wording of the VSL is unclear. Manitoba Hydro suggests changing the wording of the VSL as follows (the severe VSL of TOP-002-3, R3 is provided as an example): ‘The Transmission Operator did not notify either four or more NERC registered entities, or more than 15% of the NERC registered entities identified in the plan(s) as to their role in the plan(s). ‘
Group
LG&E and KU Serivces
Brent Ingebrigtson
No
LG&E and KU Services believe that any definition of a Reliability Directive should require that within

the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
Yes
No
LG&E and KU Services do not believe that data/evidence retention requirements should be modified by the Compliance Enforcement Authority. This potentially will result in different data retention requirements across regions. A Compliance Enforcement Authority should enforce only what is written within the standard and not have the option of expanding the requirement. 4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.
Individual
Dana Showalter
E.ON Climate & Renewables
No
ECRNA appreciates the efforts of the drafting team in eliminating duplicative requirements and efforts, as this is an important part of developing clear and concise standards. However, we are concerned about the end result of an unbounded data specification. Although requirements R1 through R4 are directed toward the Balancing Authority and Transmission Operator, these requirements have a direct impact on the other applicable entities. The lack of guidance to and expectations of the data and format could and most likely will lead to a wide range of data specifications from the multitude of Balancing Authorities and Transmission Operators in North America. Entities that own or operate facilities in multiple regions and work with many BAs and TOPs may have difficulty responding to each individual specification’s needs, including timeframe, and format. Also considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable. In addition, the sub-requirements to R1 and R2 could be written more clearly to identify who the TOPs and BAs are expected to mutually agree with and request information from. One can assume the applicable entities listed in the standard, but explicitly stating this within the standard is a better method and ensures entities are provided an opportunity to provide input in the data specification format.
No
Considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable.
Individual
Don Jones
Texas Reliability Entity
No
•In R1, the phrase “and identified as such” is redundant and unnecessary in that “identified” already exists within the sentence. Furthermore, the addition of the word “identified” or phrase “identified as such” inserts undue ambiguity and complication, and we are concerned that the “identified” concept will actually provide more opportunities for miscommunications during tense situations. •In R1, we are concerned that “Directive” is being proposed with descriptive terms (e.g., “reliability”), and if the descriptive terms are not used explicitly an entity may not be compelled to act accordingly (also may provide leverage for a perceived loophole in compliance activities that could be exploited—“I was unaware it was a {insert descriptive term} Directive”). •There should be a time frame associated with requirement R2. Perhaps add “within the timeframe determined for the Directive being issued” to end of sentence. Also, we suggest removing “identified” from requirement R2 (see comments on R1). •There should be a time frame associated with the communication required by Requirement R5. •R5

should explicitly include IROL, SOL, and Stability Limit violations in the examples since the proposed definition of Adverse Reliability Impact implies instability and Cascading outages. •We suggest rewriting R5 as follows: "Each Transmission Operator shall inform its Reliability Coordinator and other affected Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas within a timeframe that is sufficient for the RC and affected TOP's to respond to the system condition, unless conditions do not permit such communications. Such operations may include, but are not limited to, Interconnection Reliability Operating Limit (IROL) violations greater than Tv, System Operating Limit (SOL) violations, Stability Limit violations, relay or equipment failures, and changes in generation, Transmission, or Load." •In R9, the use of "continuous duration" in the revised language is confusing and should be removed. It would be better to clearly rely on the other standards that relate to identifying IROLs and SOLs (including duration limits), which may have multiple time limits associated with various operating conditions. We note that an SOL may not be based on a single Facility Rating but may actually be a group of Facilities aggregated into a single limit. We suggest saying: "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria, including duration, upon which it is based".
Yes
No
•Regarding R1, we are concerned that the proposed requirement gives each TOP too much latitude to determine what data it considers necessary. This may cause confusion due to significant differences in data specified by different TOPs and the ability of TOPs to unilaterally change their data specifications. We would prefer that the standard include a basic list of data to be included in the specification. •The reference to "mutually agreeable format" in R1 part 1.2 is problematic because it allows the respondents to interfere in the TOP's data collection process. The TOP should be allowed to dictate a reasonable format for data submission. •In R2, we are opposed the removal of "Operational Planning Analyses" (OPA) for a Balancing Authority in this requirement, because the BA is "the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time." A BA should create a documented specification for the data necessary for it to perform an OPA just as a TOP does. •The reference to "mutually agreeable format" in R2 part 2.2 is problematic because it allows the respondents to interfere in the BA's data collection process. The BA should be allowed to dictate a reasonable format for data submission. •In R3 we suggest changing "operating analysis" to "Operational Planning Analysis," which is a more precise term for what appears to be intended. The same change should be made in Measure M3. •In R4 we suggest adding "Operational Planning Analysis," to be consistent with our comment that R2 should require "Operational Planning Analysis" data in the BA's data specification. •In the Measures, please check and correct the references to Requirement numbers – some references are to the wrong requirements. •Under Data Retention, in the 4th bullet starting with "Each Balancing Authority…", the phrase "and operating analysis assessment processes and" should be struck because it does not align with requirement R4 as currently written. However, we support adding "Operating Planning Analysis" in R4, and this data retention reference should be consistent with the requirement.
No
•Regarding the VSL for TOP-001-2 R5, we suggest that it be based on a percent of applicable TOPs rather than number of TOPs, which would accommodate various sized entities. •Regarding the VSLs for TOP-001-2 R9 and R11, we recommending adding a time duration reference relating to SOL violations, even if it is not a definite number of minutes. •Referring to the VSLs for TOP-003-2 R1, there are only four elements listed, so the reference to "four or more" is nonsensical. Also, there is no difference between omitting four elements and not providing a documented specification at all. Finally, the four listed elements do not appear to have equal importance – perhaps the VSL levels should be assigned based on which elements are missing.
•Referring to the posted "Issues Database," under Order 693 ¶ 1604/1608, the red-lined language is not actually in the referenced requirement. Does the drafting team contend that the proposed requirements satisfy this FERC directive? •Referring to the posted "Issues Database," under Order 693 ¶ 1636 (TOP-004), this document suggests that a 30-minute limit is contained in the requirements, but that limit is not in the language that is now posted. Does the drafting team contend that the proposed requirements satisfy this FERC directive? In general, NERC needs to make sure the

Issues Database is consistent with the latest draft of the requirements. •The VRF/VSL Assignment Document needs to be cleaned up. There are numerous references to incorrect requirement numbers. On page 3, TOP-001-2 Requirement R3 is struck from the list of “High” VRFs, but it is assigned a high VRF in the posted standard. Also, the title of TOP-001-2 is stated incorrectly in this document (at the beginning).
Individual
Scott Berry
Indiana Municipal Power Agency
no comment
no comment
No
IMPA believes that the entities (Transmission Operator and Balancing Authority) should be required to create a documented specification that lists exactly what the entities (in R5) need to provide to them to meet the requirement and not be allowed to say that “it is in our manuals and/or agreements.” When the Transmission Operator and/or Balancing Authority only references their manuals, it is up to the entity (in R5) to read the manuals that are referenced and then try to come up with a documented specification listing on their own which may or may not include everything that is required by the TO or BA which makes the current draft standard’s language very ambiguous. IMPA is not objecting to these entities using manuals as long as a specific documented specification is created and distributed that does more than just list the name of manuals. The documented specifications need to be detailed in what is required from entities to aid in preventing possible non-compliance issues due to an entity missing an item in a manual or including unnecessary items due to being left to their own interpretations.
no comment
No other comments
Individual
Rich Salgo
NV Energy
Yes
Yes, however, there are a few points to note: Part A, Section 1 continues to title this standard as "Coordination of Transmission Operations, while the header of the Standard was changed to simply "Transmission Operations". The requirements R6 and R8 appear to be outside the realm of real-time operations, R6 dealing with planned outages of telemetry, comm, and control equip, and R8 dealing with communication of SOL's or other limits. It is confusing to mix in Operations Planning type requirements in a standard that otherwise deals with real-time grid operations. Suggest relocating these two to the Operations Planning Standard, TOP-002-3.
Yes
Yes
In the re-draft of these three standards, TOP-001, -002, and -003, we seem to have lost the concept of Planned Outage Coordination for BES facilities (a whole Standard was devoted to the process). In viewing the mapping document, it is stated that the requirements for such outage coordination that used to reside in TOP-003-1 are now replaced by R1 and R2 of TOP-003-2. If this is the case, then all of the activities of outage coordination are to be encapsulated in the clause "documented specification for the data necessary for it to perform its required Operational Planning Analyses..." While it may be covered in this extremely broad clause, the SDT nevertheless gave prominence to the coordination of telemetry outages within a specific requirement R6 of TOP-001-2. If telemetry outages have a separate requirement, then shouldn't planned outage coordination of BES facilities rise to the level of importance that would merit its own requirement?
Individual
Gregory Campoli

New York Independent System Operator
No
Communications must be a well defined, consistent and established process to promote clear and accurate communications between operators for both normal and emergency conditions. This standard could be interpreted as to require an extra phrase during emergencies that would unnecessarily complicate communications. The requirement is reasonable if the identification of a 'Reliability Directive' may be done in a policy or procedure that is communicated to the BA, GOP, DP or LSE as a communication protocol that addresses normal and emergency communications. Otherwise requiring different verbal communication protocols for normal or emergency conditions will add a level of risk currently not observed.
Individual
Martin Bauer
US Bureau of Reclamation
Yes
Yes
No
The language change in R1 has not been incorporated into the sub requirements. The requirement R1 was modified to eliminate the second party. A mutual agreement is required in R 1.2 but only party is listed in R1. The language should specify that the TOP is to coordinate its data requests with the appropriate entities and seek mutal agreement on the format.
Yes
Individual
Alice Ireland
Xcel Energy
No
R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity informs its Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. We would like to see additional clarification to clarify “equipment”, suggest using “equipment limitation” or “equipment rating” R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. This requirement should be modified so as not to place the burden on the assisting entity to demonstrate that the requesting entity has implemented “comparable emergency procedures”. Suggest the following language: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment ratings, regulatory, or statutory requirements. R5. Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. This requirement appears to duplicate PRC-001-1 R2 and R5. It is assumed, but cannot be verified that those requirements will be eliminated in a future approved version of that standard. R9 - We appreciate the drafting team’s efforts. However, we are still concerned that R9 will not allow the Transmission Operator the flexibility to identify the best SOL

recovery approach, without incurring a violation of the requirement. Instead, the TOP may be forced to shed load in order to avoid violating the requirement. This is not ideal, especially when the situation could be mitigated successfully with alternative measures. It is not clear if an entity is allowed to use an RC-approved contingency plan to mitigate a situation that would cause a Facility Rating violation (i.e. the Facility Rating is the SOL), without also incurring a violation of R9. To further explain, if an entity foresees exceeding an SOL in its OPA, and obtains approval from the RC on their proposed contingency plan (which includes a Facility Rating violation), will that entity be considered in violation of R9 once the exceedance occurs and the contingency plan is implemented? R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. This requirement should specify a sustained period which establishes when it is considered that the entity has returned below the limit (or some other value so as to not misconstrue momentary recoveries as meeting this requirement).
Yes
No
Applicability – why are Distribution Providers not subject to this standard? Is it possible that a TOP or BA may need information form a DP to perform an "OPA"? "Mutually agreeable" in 1.2 should be removed. The TOP and BA should work with the subject entities, however stating that something must be mutually agreed upon could create delivery and acceptance of data in a less than desired form solely to meet the words of the requirement.
There is reference in each draft standard to deleting some requirements from PRC-001 but those proposed changes are not show in any proposed drafts or implementation plans (only 1 PRC-001 requirement is listed in the implementation plan).
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst has the following comments for consideration: 1. Definition of Reliability Directive - ReliabilityFirst believes there could be a possible issue with the definition of "Reliability Directive" being developed and approved via another drafting effort (i.e. Project 2006-06). In the hypothetical situation where the TOP-001-2 standard is approved and the definition of "Reliability Directive" is drastically changed through the Project 2006-06 effort, there could possibly be a disconnect between the TOP-001-2 requirements and the "Reliability Directive" definition. Also, ReliabilityFirst recommends adding a parenthetical "(e.g. IROL or SOL violations)" to the end of the definition for further clarity. 2. R2 – There is no time qualifier specified in R2 dealing with the timeframe in which the applicable entity has to inform its Transmission Operator of its inability to perform an identified Reliability Directive. ReliabilityFirst recommends the SDT consider adding language to include a timeframe for the entity to inform the Transmission Operator (such as one hour). Absent any specified timeframe, an applicable entity could hypothetically inform its Transmission Operator of its inability to perform an identified Reliability Directive 30 days after the Reliability Directive was issued, and still be compliant based on the current words of the requirement. 3. R4 – The term "emergency" is used within this requirement and ReliabilityFirst seeks clarification on whether this is referring to the NERC definition of "Emergency" (as defined in the NERC Glossary of terms)? If so, this term should be capitalized. 4. R5 - The last sentence in R5 is not really a requirement, but rather a measure on how to comply with the requirement. ReliabilityFirst recommends deleting the last sentence of R5 and incorporating it into the corresponding Measure. 5. R6 – ReliabilityFirst recommends removing the term "negatively impacted interconnected NERC registered entities" and replace it with the associated functional entities (e.g. Balancing Authority, Generator Operator, etc.). 6. R8 – ReliabilityFirst recommends removing the term "while not IROL's" from R8. SOL is a NERC defined term and the extra qualifier is not needed. 7. R10 and R11 – ReliabilityFirst recommends swapping the order of R10 and R11. From a chronological standpoint, the Transmission Operator will "act or direct others to act, to mitigate…" (R11) prior to "informing its Reliability Coordinator of its actions" (R10). 8. Data retention – ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the

last sentence states “the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit” as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.
No
ReliabilityFirst has the following comments for consideration: 1. R1 – ReliabilityFirst recommends removing the rationale box from the standard. ReliabilityFirst believes this is not really the rationale for the requirement but rather explains how to measure (show evidence) for the requirement. 2. R2 – ReliabilityFirst recommends deleting the following words from the requirement, “which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1”. ReliabilityFirst believes this language does not add anything to the requirement. 3. R2 and R3 – R3 requires the Transmission Operator to notify all NERC registered entities identified in the plan(s) but there is no corresponding requirement for the Transmission Operator to identify NERC registered entities in their plans. ReliabilityFirst recommends incorporating this concept into R2. 4. Data retention – ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the last sentence states “the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit” as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.
No
ReliabilityFirst has the following comments for consideration: 1. R1 and R2 – ReliabilityFirst recommends changing the phrase “shall create…” to “shall have…” in R1 and R2. 2. R1 and R2 – ReliabilityFirst recommends changing Part 1.2 and Part 2.2 to state “A format”. ReliabilityFirst believes it may be difficult to audit and enforce the phrase “mutually agreeable”. 3. R3 – ReliabilityFirst seeks clarification on the term “operating analysis assessment” used in R3. Is this language referring to the Transmission Operators Operational Planning Analyses as required in R1? If not, can the SDT clarify what the phase “operating analysis assessment” is referring to? 4. R3 and R4 – ReliabilityFirst seeks clarity on what the phrase “NERC-mandated reliability requirements” is referring to? Is it referring to FERC approved NERC standard requirements or does it encompass NERC Directives, CANs, NERC bulletins, etc. as well? 5. R3 and R4 – R3 references “those entities” and R4 just references “entities”. ReliabilityFirst recommends modifying either R3 or R4 to use consistent language. 6. Data retention – ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example the last sentence states “the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit” as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.
No
For the TOP-001-2 standard, ReliabilityFirst disagrees with the VSLs for the following reasons: 1. VSLs for R3, R5 and R6 – ReliabilityFirst recommends adding the gradated language of “or X% or less of the entities whichever is less” to the VSLs (this is consistent with the language stated in the TOP-002-3 and TOP-003-2 VSLs). This is needed for smaller Transmission Operators which may have less than four other TOPs to inform. 2. Note in front of VSL 5 – ReliabilityFirst recommends removing the note in front of VSL5 since the note is contrary and is in conflict on how the VSL is set up.
Group
Kansas City Power & Light
Michael Gammon
No
Requirements R3 & R5 requires TOP's to notify all other "affected" TOP's in instances of emergency or

Adverse Reliability Impact. The term "affected" is a debatable condition and subject to interpretation. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Recommend the requirement be modified to alert other TOP's whenever a TOP in an emergency or Adverse Reliability Impact operating condition becomes aware of operating conditions that would result in exceeding an SOL or IROL operating limits under N-1 contingency conditions for other TOP facilities. Modifications for these two requirements will result in subsequent changes to the Measures and VSL's for requirements R3 & R5. In requirements R9 and R11 the 30-minute transition from an unknown operating state to a known state is lost for operating from an n-1 state to a n-2 state therefore leading to an immediate violation of R9 if the facility rating is exceeded. Also, the inclusion of IROL's in R10 and R11 makes these requirements confusing as to who is responsible for mitigation, IROL's should be removed from here as they are considered in the IRO requirements, these requirements should only address SOL's. Requirement R8 uses the term "continuous duration". The term "continuous duration" will be subject to interpretation as to its meaning and intent. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Also, a draft Reliability Directive definition is included in this standard but needs approval in the COM-002 standard, what if COM-002 does not get approved?
No
The words "develop a plan" in R2 are too broad. Recommend the requirement be modified to include, "within its TOP area" as in R1. Also the use of "Contingency event conditions" is not clear in requirement R1. Recommend specifying n-1 as the contingency scope.
No
These requirements do not recognize the limitations of data exchange capability with an entity and the sources of data an entity has. Recommend these requirements be modified to include "within the data exchange capabilities and data available of the recipient of the data specification".
No
The VSL for TOP-003-2, R5 does not recognize partially satisfying a request for data. Recommend the SDT consider a graduated set of severity levels similar to the other requirements in TOP-003-2.
No other comments.
Individual
Don Schmit
Nebraska Public Power District
No
Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. In R3, suggest rewording as "Each Transmission Operator shall inform its Reliability Coordinator, and other Transmission Operators, of each actual and anticipated Emergency that they are known or expected to be affected by, based on its assessment of its Operational Planning Analysis". The existing language doesn't clearly specify what is to be communicated with affected entities. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9, even in situations where the inititating event was outside of design criteria. Current language allows exceedance of an IROL for a specific time, but does not appear to give any time to readjust the system for the less severe SOLs. This does not seem reasonable. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? Suggest "Each Transmission Operator shall inform its Reliability Coordinator of each SOL identified by the Transmission Operator as supporting the reliability of its Transmission Operator Area". With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather

than ‘the’ RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
No
Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. We suggest the following language for R1: “Each Transmission Operator shall have an Operational Planning Analysis assessing whether the planned Transmission Operator Area operations for the next day will exceed the area Facility Ratings or Stability Limits during anticipated normal and Contingency (at a minimum N-1 Contingency planning) event conditions.” Requiring the TOP to develop a plan to operate within each IROL in R2 is too broad. To narrow the scope of this requirement we suggest inserting the phrase ‘within its Transmission Operator Area or for which it has been notified by another TOP under R3’ in R1 immediately following (IROL).
No
Comments: Requirements R1 & R2 do not put any meaningful bounds on the data that a TOP or BA may request in the name of monitoring real-time operations. There is no check or balance on spcifying timeframes when the data is required either. Attachment 1 TOP-005-1 contained the type of data that may be required and as such provided a fremework for what type of data was required for real-time monitoring of the Bulk Electric System. As written, it would be possible for a BA or TOP to request data that a registered entity does not have available and require it in an unrealistic timeframe. This puts those entities in a position where they cannot comply with the standard, even though the data requested may not be important in the monitoring of the Bulk Electric System. There need to be reasonable limits on the information requested and how quickly new information may be required from other registered entities.
No
TOP-001-2, R3 Moderate VSL – the word “affected’ has been omitted and needs to be inserted. TOP-003-2, R1 & R2 – The use of the term ‘element’ in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 – The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn’t this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
The definition of Reliability Directive is contained in COM-002-3 and that standard hasn’t been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Individual
Bob Thomas
Illinois Municipal Electric Agency
No
Illinois Municipal Electric Agnecy supports comments submitted by the SERC OC Standards Review Group and the ISO/RTO Standards Review Committee concerning the need to address the “Reliability Directive” definition in concert with COM-002-3.
No
Illinois Municipal Electric Agency supports comments submitted by Indiana Municipal Power Agency concerning the need for clearer communication of data specifications in R3 and R4 in order to facilitate compliance with R5.
No
Illinois Municipal Electric Agency supports comments submitted by the ISO/RTO Standards Review Committee concerning the need to build some flexibility into the VSL for TOP-003-2 R5.
Illinois Municipal Electric Agency appreciates SDT efforts to develop a sixth draft for this proposed Reliability Standards development. While we realize the SDT will never be able to resolve all concerns, it appears from our own review and our review of other entity comments that additional revisions are needed to achieve a level of quality that will minimize difficulties complying with these Reliability

Standards.
Individual
Greg Rowland
Duke Energy
No
While the drafting team has made several improvements to this standard, we believe these additional changes are needed: • The definition of Reliability Directive includes the defined term “Adverse Reliability Impact”, which should be replaced by the actual wording of latest BOT-approved definition of “Adverse Reliability Impact”, since it has not yet been approved by FERC. If the SDT decides not to replace Adverse Reliability Impacts with the actual wording of the latest BOT-approved definition, then the SDT should delete the “s” from “Impacts”. • R8 – We believe that the phrase “supporting its internal area reliability” should be further clarified in some way. The inclusion of the undefined concept of “supporting internal area reliability” creates undue compliance risk, since auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”. The drafting team could examine the disturbance reporting criteria in EOP-004-1 Attachment 1 to help develop a reasonable threshold for reporting SOLs to the Reliability Coordinator. • R8 – Consistent with R3, the Time horizon for R8 should only be Operations Planning. • R9 – The change that has been made to R9 could be interpreted to result in a violation if a facility rating is exceeded for any amount of time at all. Similar to an IROL’s Tv, SOLs identified under R8 should have an identified time period (such as 30 minutes) for mitigation without a violation. A change to R9 should be coupled with development of a reporting threshold for R8 as discussed above. • M1 – typo, left the “u” off the word “unless”. • Measures for R8 and R9 should be changed consistent with our suggested revisions to the requirements.
No
• R2 – Consistent with our comment above on TOP-001-2 Requirement R8, the phrase “supporting its internal area reliability” should be further clarified in some way. • M2 typo – the word “plan” has an extra “n”.
Yes
• R1.1 – Consistent with our Question #1 comment above on using the actual wording of the BOT-approved definition of “Adverse Reliability Impact” since it has not yet been approved by FERC, “Operational Planning Analysis” has likewise not yet been approved by FERC as of the latest version of the Glossary posted on the NERC website, December 13th, 2011. Suggest using the wording of the defined term. If the SDT decides to instead keep the defined term, “Analyses” should be “Analysis”. • R3 – Current wording is awkward. Suggest rewording as follows: “Each Transmission Operator shall distribute its data specification to entities that have data required for operating analysis assessment processes and reliability monitoring tools used by the Transmission Operator in meeting its NERC-mandated reliability requirements.” • R4 – Current wording is awkward. Suggest rewording as follows: “Each Balancing Authority shall distribute its data specification to entities that have data required for reliability monitoring tools used by the Balancing Authority in meeting its NERC-mandated reliability requirements.” • Measures and Data Retention – change to align with suggested R3 and R4 rewording above.
No
• TOP-001-2, R8 – Consistent with R3, the Time horizon for R8 should only be Operations Planning. • TOP-001-2 VSLs for R8 and R9 should be changed consistent with our suggested revisions to the requirements. Also see comment below regarding use of percentage ranges. • TOP-002-3 VSLs for R3 – the addition of the percentage range on the Lower VSL makes no sense. The “whichever is less” phrase on the other VSLs could push a violation into a higher VSL because of the percentage range. For example, if the TOP had 10 entities to notify and failed to notify one, then it would be a Moderate violation (10%) instead of Lower. If the TOP had 100 entities to notify and failed to notify four (less than 5%), then it would still be a Severe violation. • TOP-003-2 VSLs for R1 - “Analyses” should be “Analysis”, since “Operational Planning Analysis” is a defined term. • TOP-003-2 VSLs for R2 – Severe VSL should just say “four” instead of “four or more” because there are only four required elements. • TOP-003-2 VSLs for R3 and R4 – the addition of the percentage range on the Lower VSL makes no sense. See comment on TOP-002-3 VSLs for R3 above.

Individual
Edvina Uzunovic
The Valley Group, a Nexans Company
TOP-004-2 R4: If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits, as determined by System Operating Limits or real-time measurements, have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits (SOLs or Real-Time Limits) within 30 minutes. TOP-006-2 R1.2 Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources, as determined with SOLs or Real-Time Calculated limits, available for use. TOP-006-2 R2: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real time operating capacity, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. TOP-008-1 R2: Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall operate the Bulk Electric System to the actual real-time limits (if available) or the most limiting derived parameter. TOP-008-1 R3: The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. The Transmission Operator shall review the real time status and capacity of transmission facility prior to disconnecting, if applicable. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter. TOP-008-1 R4: The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation. If applicable, and prior to immediate mitigation, the Transmission Operator shall review real time status and capacity of the equipment, and based on those, made necessary adjustments.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
Please provide clarity on the phrase "support its internal area reliability" in R8.
No
Please provide clarity on the phrase "support its internal area reliability" in R2.
Yes
No
There is a mistake in the mapping document for TOP-001-2 R11 as the language doesn't match the language in the Standard. There is additional language in the mapping document that states "within 30 minutes," which the standard does not, and should not say. This occurs on page 36 for the mapping of current TOP-007 R2 to proposed TOP-001-2 R11. Additonally, SCE&G believes that it would be erroneous to remove TOP-004 R5 on the basis of the functional model. The functional model for the TOP stipulates that the TOP "is responsible for the real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably." If a situation were to arise where there was not sufficient time to contact the RC or if the RC was taking action that would put the TOP in jeopardy, SCE&G believes that the TOP has the right to separate from the Interconnection to protect the reliability of its system as is

spelled out in current standard TOP-005 R5.
Group
SERC OC Standards Review Group
Gerald Beckerele
No
We suggest that the definition of Reliability Directive should be modified as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or “an event that results in Bulk Electric System instability or Cascading”. We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition. We suggest the Standard Drafting Team further clarify or define the term “supporting internal area reliability” as an aid in demonstrating compliance and how this requirement enhances reliability. We suggest including “Real-time Assessments” in this standard to clarify Operations Planning and same day operations time horizons (Requirement 8). We request that the drafting team review and explain the differences in the time horizons for Requirements 3, 5 and 8.
No
Why did the Drafting Team use the terms “Facility Ratings” and “Stability Limits” in Requirement 1 rather than SOLs and IROLs as used in subsequent Requirements? We suggest the Drafting Team further clarify or define the term “supporting internal area reliability” as an aid in demonstrating compliance and how this requirement (R2) enhances reliability.
No
There appears to be ambiguity for R1 and R2 - is the VSL applicable to the TOP/BA requesting the data or is it applicable to the TOP/BA providing the data? If it applies to the TOP/BA requesting the data we would suggest that the SDT be consistent with the VSLs in IRO-10-1a.
See responses to questions above.
Data retention requirements for TOP-001-2. TOP-002-3 and TOP-0003-2 need to align with the expectations of the compliance entity. “The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Group
Georgia System Operations
Neil Phinney
Yes
GSOC agrees in general but feels that some clarity should be provided. The purpose of the language "each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis" (OPA) is not clear. Is the intent to clarify the meaning of SOL? If so the definition in the glossary should be updated to clarify the meaning and the clarification should be removed whenever used in TOP-001, 002, or 003. Is the intent to limit which SOLs are being referred to? Not each SOL but each SOL which have been identified as supporting the internal area reliability based on the assessment of its OPA. Could this language be deleted and still convey what is required?
No
GSOC feels that some clarity should be provided. In R1, the rationale confuses things. It states things that are not in the requirement and goes beyond the requirement. If something is intended by the language of R1 other what is stated, then that intent should be clearer in the requirement. For example if a process is required, then state so in the requiremnt. It should not be in a rationale. Also, the comment in the rationale about being able to complete the analysis even if tools are not available is inappropriate in this standard since the situation is covered in EOP-008-1. Remove the rationale and if needed clarify the requirement. R1 states that the TOP should be allowed to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. It does not state that an assessment of this must be done, only that it be allowed. R2 states that the TOP shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which has been identified by the TOP as supporting its internal

area reliability, identified as a result of the OPA performed in Requirement R1. R1 does not require that IROLs and SOLs be identified. What if the TOP does not identify if there are any SOLs as a result of the OPA? There are other examples in these standards in which something in the OPA is referred to but is not required to be in the analysis. Better clarity is needed regarding just what the end results of the analysis must be. R3 requires that entities identified in the plan be notified as to their role. Would this be initially and whenever their role changes thereafter? Or just once? Data Retention: It states that if a TOP is found non-compliant, it shall keep information related to the non-compliance until found compliant. It is inappropriate to use the phrase "found compliant." NERC and the REs do not find entities compliant.
No
R5 is too unilateral. A TOP could send a spec to an entity for some data that the entity is not able to provide and per this requirement the entity will still be required to provide it. There must be some mutual agreement to more than just the format. There must be agreement to what can be provided and that the data is needed by the TOP’s operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements. Also some provision must be allowed to cover when data or the transfer method is unavailable (e.g., when an RTU goes down). A similar situation applies to BAs sending a spec to an entity.
GSOC believes that all 3 standards should be voted on together in one vote. They are too inter-related. One or two of these should not be approved if one of them is not approved.
Individual
Terri Pyle
Oklahoma Gas and Electric
No
A. In the draft TOP-001-2 standard, R1 and R2 both address complying with Reliability Directives. OG+E suggests these two requirements be combined into one requirement using similar language found in other standards that contain the same Reliablity Directive requirement, such as IRO-001-1.1 R8 and the previous version of this standard for consistency purposes. B. Mitigation of IROLs is ultimately the responsibility of the RC. TOPs act under the direction of the RC when mitigating IROLs. TOP-001-2 R11 should clarify by adding the following to the beginning of the requirement. "Under the direction of the RC, each TOP shall act or direct others to act…". C. Please clarify the meaning of "internal area realiability" in R8. D. In R9, "continuous duration" warrants additional clarification. Is this 5, 10, 30, 60 minutes of operating outside the SOL? Or only continuous operation outside of SOL that results in ultimately exceeding the Facility Rating?
No
Regarding R2, please consider additional clarifying language that each TOP need only develop a plan to operate within IROL and SOL that is applicable to them. Also, clarify what "internal area realibility" means - is this the same as Transmission Operator Area discussed in R1?
Yes
Individual
Julie Lux
Westar Energy
Yes
No
The stated rationale for R1 raises more concerns than the actual language in R1. How can an entity complete an analysis by procedure? The rationale seems to indicate that an Operational Planning Analysis is possible without tools, please explain. Are anticipated contingency event conditions intended to be N-1 from the planned system configuration?
Yes

No additional comments.
Group
MRO-NSRF
Will Smith
No
Issue: Upon review of the NERC Glossary of Terms, please drop the “s” from “…or Adverse Reliability Impacts” within the definition of a Reliability Directive. Issue: M1; It is not necessary to repeat the Requirement within the Measure. Recommend “unless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1”, be removed from this Measure. Issue: M4; It is not necessary to repeat the Requirement within the Measure. Recommend “unless such actions would violate safety, equipment, regulatory, or statutory requirements”, be removed from the Measure. Issue: Upon review, it is noted that ‘Coordination of’ has been struck from Purpose, however not removed from the Title of the Standard. Recommend changing ‘interconnection’ in the Purpose to ‘Bulk Electric System (BES)’ Issue: R3: The statement “…Transmission Operators that are known or expected to be affected…” the use of “known or expected” is redundant. Recommend removing ‘known or expected’ and have the requirement rewritten as follows: Issue: R3: Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. Issue: R8: The statement “…its internal area reliability…” should be clarified to state: R8: Each Transmission Operator shall inform its Reliability Coordinator of each of its SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its Transmission Operators area based on its assessment of its Operational Planning Analysis. Issue: M8: statement “…its internal area reliability…” should be clarified to state: “…has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis…” Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you can’t draw SOLs into the same category as IROLs unless you clearly indicate these standards only apply to a subset.
No
Issue: The SDT uses a non FERC approved term of “Operational Planning Analysis”, This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval. Issue: R2: statement “…its internal area reliability…” Should be clarified to state: R2: Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: statement “…its internal area reliability…” could be clarified to state: “…has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis…”
No
Issue: There is a great possibility of “double jeopardy” when R3 and R4 have in part the statement of “…in meeting its NERC-mandatory reliability requirements.” So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown “…in meeting its NERC-mandatory reliability requirements” then they would be found non compliant with this Standard. It is not clear why this Standard is being written with the statement of: “…in meeting its NERC-mandatory reliability requirements”. As stated in the NERC Standard Process Manual, under Background, “NERC works with all stakeholder segments of the electric industry, including electricity users, to develop standards for the reliability planning and reliable operation of the bulk power systems. Recommend that “…in meeting its NERC-mandatory reliability requirements”, be deleted and replaced with “reliable operation” as defined as “…operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance…”. Or, please review IRO-010-1a, requirement 1 and use

like terminology for this Standard.
None
None
Group
Western Area Power Administration
Brandy A. Dunn
Yes
Yes
No
Data an entity specifies in requirement documents need to have some kind of reasonability limit or explanation as to what the data will be used for. As written a TOP or BA can request anything they want and other entities will be required to provide that data, even if the requested data is not available as requested. An entity can also request data not pertinent to the reliability of their system and other entities will still be required to provide it. An entity required to provide the data should have an opportunity to challenge the need for data requested. At least one BA in WECC is running a market and data provided will be used in their market, not for reliability.
TOP 1 and 2 as written are generally acceptable. TOP 3 opens doors for manipulation.
Individual
Thad Ness
American Electric Power
No
R7, R9, R10, & R11 – It needs to be clarified whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader. Taken together, the combination of R7 and R9 appears redundant with R11, as meeting the objective of R7 and R9 would imply taking the proper mitigating measures. AEP suggests either eliminating both R7 and R9 or eliminating only R11. If r7 and R9 were to be eliminated, the references to magnitude and duration should be removed from R11, as the associated measure is binary in respect to the limit, i.e., either the limit has been exceeded or it has not. It would be premature for AEP to support the associated VSLs and VRFs given the objections stated above.
Yes
R2: Once again, it needs to be clarified whether this requirement is in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader.
Yes
R5: It should be noted that some of the information that could potentially be requested may already be available, for example on reliability coordinator systems. AEP suggests that the requirement be modified so that it does not unintentionally create an edict to provide “any data” to parties simply because R5 could be interpreted as allowing requests of any kind. The possibility of a dispute resolution process managed by the reliability coordinator(s) might also address these possible scenarios. Such a process should address, at a minimum, specifics such as timing, format and general logistics concerning the requested data. AEP does not currently have any text to suggest in this regard, but asks the SDT to consider such a change.
No
In general, the VRFs and VSLs are too severe and punitive. Because of this, as well as our objections with the redundancy of requirements in TOP-001-2, AEP cannot support the proposed VRFs and VSLs.
Individual
Brenda Truhe

PPL Electric Utilities
No
We believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
Individual
Bill Keagle
BGE
No
BGE concurs with ISO/RTO Standards Review Committee Position: Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
No
BGE concurs with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
No comment.
No comment.
We realize that SDT for Project 2006-06 is responsible for defining Reliability Directive; however, we would like to reiterate our position that the definition must capture the identification concept that is reflected in Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. Additionally, the currently proposed definition of Reliability Directive is also contained in COM-002-3 and IRO-001-3 which have not been approved at this time. What happens if the TOP standards are approved and the COM and IRO standards are subsequently not approved or change? The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. Since the two projects appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently. We are voting affirmatively because we support the improvements achieved by the drafting team work so far. However, we raised remaining concerns with the standard proposal on the comment form submitted on behalf of BGE. We expect the drafting team to continue to make clarifying changes until the end of this stakeholder process. The greater the clarity in the final product, the less risk of contradictory

perspectives on compliance.
Group
Constellation Energy
Brenda Powell
No
The definition of Reliability Directive is an improvement but the definition must capture the identification concept that is reflected in the Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. We suggest the following revision to the definition and it should follow through to Project 2006-06 (COM-002-3 and IRO-001-3), eventually being added to the Reliability Standards Glossary of Terms. A communication identified as a Reliability Directive by a Reliability Coordinator, Transmission Operator, or Balancing Authority to initiate action by the recipient to address an Emergency or Adverse Reliability Impact. The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. CCG, CECD and CPG agree with ISO/RTO Standards Review Committee Position: Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well
No
CCG, CECD and CPG concur with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
No
The Drafting Team may want to consider addressing a time period for responding to a data request to ensure parties are given time to respond. For example, a BAs data request may be driven by the TOP's data request. If a BA receives a data request for information from the TOP that sources from a GOP, the BA will need to establish a data request from the GOP that has the same deadline. If the GOP is unable to supply the data they may be non-compliant if they do not meet the deadline.
The definition of Reliability Directive is contained in COM-002-3 which has not been approved at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved or change? Since the two projects appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently.
Individual
Kirit S. Shah

Ameren
No
R2. When is “shall inform” to occur; timely, promptly, … It would be injurious to BES reliability for the TOP to get such information, say 15 minutes or half-hour later as many other things are likely to be put in place on the assumption the directive is “ok”. R3. The wording is incorrect it implies the TOP will notify the RC and its TOP’s. The word other may be missing. But even with other the question it begs which other TOP’s? It could be argued that the RC only needs to know Emergencies that are both actual and anticipated. They would want to know about them whether they are actual or anticipated. This direction here is not clear; it may be helpful to use two sentences to address and clarify the issues of this requirement. R4. What is meant by emergency assistance is not clear; clarify and provide examples. Is it emergency energy? Is it emergency food? Is it emergency crews? This ambiguity is a compliance nightmare as you have to prove you have everything covered that could loosely be interpreted as emergency assistance. If the SDT has an idea what they are expecting, it should be listed. If they don’t have an idea of what constitutes emergency assistance, then we recommend removing it from the Requirement. R5. The Requirement should be re-written to say “Each TOP shall inform only if it adversely affects others its RC and other TOP’s (Which other TOP’s? This direction here is not clear; clarify) of its operations known or expected to result in an Adverse Reliability Impact …” R6. What is meant by negatively impacting is not clear; clarify and provide examples. For example, using the words as listed, economic impact might be a consideration. The Standard should not be setting up a condition where TOPs tell GO/GOPs that they might suffer economic harm as a result of one of the communication channels being down. As currently worded this might lead to a civil issue instead of a BES reliability issue. R8. There are SOLs that are developed in real-time (as evidenced by the multi-time-horizon assigned). It might be possible for such an SOL to develop and have to be resolved for local area reliability only, before the RC could be notified. This Requirement should insert the word planned before SOL. Alternatively, insert where time permits in place of real-time. R9. What is meant by continuous duration is not clear; clarify. Is it 5 minutes, 15 minutes, an hour, a day? Anything more than 5 minutes is likely to be in the thermal time-constant period where rating could be affected. We feel that the real intent of this requirement is that TOPs resolve SOLs. It is not so much how long, as it is that they are not purposely delaying the resolution. The Requirement should be re-written to say “The TOP’s will resolve as soon as possible anys SOL…… with no intentional time delay…” R10. The Requirement as written should be prefaced with “when time permits, each Transmission Operator…..” The idea of time permitting is alluded to in R5, “unless conditions do not permit such communications“.
No
R1. The current language invites a retrospective assessment and a potential compliance issue that if a bad event occurs that was not in the forecast, it may call into question whether the TOP adequately “allowed it to assess” whether operations where within limits. We recommend SDT re-write the requirement: “Each TOP shall have an Operational Planning Analysis that represents projected System conditions for the next day, within its Transmission Operator Area, to identify any projected exceedance of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.” R2. Although the time-horizon assignment provides some cover for real-time SOLs, it would be preferable to add direct clarification to the Requirement as follows. “Each TOP shall develop a next day plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) …” R3. Taken literally, this Requirement could require TOP notification to a GOP/PSE/LSE that they will be dispatched down in real-time for a projected congestion issue (SOL). This does not make sense and certainly not in organized LMP markets where they would have advance knowledge of market conditions AND FOR THINGS THAT ARE ROUTINE. This is the nexus of the problem for us with this Requirement. The need to notify others of their roles should be restricted to unusual actions in the case of SOL resolution. Arguably this could be true for IROLs too but given the impact perhaps it could remain. We suggest that the Requirement say, “Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) when those actions are unusual or abnormal actions.” OR “Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) for the resolution of IROLs or when those actions are unusual or abnormal actions for the resolution of SOLs.”
No
R1. Each TOP shall create a documented specification for the data necessary for it to perform its

required Operational Planning Analyses and Real-time monitoring. The specification shall include: 1.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the TOP. This is illogical and needs to be clarified or removed. 1.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R2. Each BA shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. The specification shall include: 2.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the BA. This is illogical and needs to be clarified or removed. 2.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R3. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert “from R1” There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they should be spelled out explicitly here and likely in R1 as well. R4. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert “from R1” There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they should be spelled out explicitly here and likely in R1 as well. R5. We recommend re-writing: “Each TOP, BA, GO, GOP, IA, LSE, and TO receiving a data specification in Requirement R3 or R4 shall provide the data associated with said data specification. “
No
See comments in question 5 regarding VRF.
We highly recommend that you do not lump requirements that include SOL with IROL. IROLs by definition should have VRFs higher than SOL. So it is not possible to properly assign the VRF consistent with the NERC VRF/VSL Guideline documents. We would suggest that the SDT could review what the FAC-003 SDT has done and then provide separate Requirements when there are known and expected VRF differences for different elements covered by a combined Requirement.
Group
ACES Power Marketing Member Standards Collaborators
Jason Marshall
No
We largely agree with the changes but have identified the following specific issues. We disagree with removing Bulk Electric System (BES) from the purpose of the standard. NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Substituting BES for “interconnection” in the purpose statement may solve this issue. While the title contained in the header was changed to “Transmission Operations” the actual title was not changed. They should match. For simplicity, we recommend striking “known or expected to be” from Requirement R3. As it is written now, it is more confusing. First, the TOP, can only notify other TOPs that it knows are affected. Second, the use of “expected” implies that something different is meant than known. If so, what is the intention of the meaning and whose expectation is it: the responsible TOP, the other TOP, the auditor or some other entity? There is a similar issue regarding “known or expected to result in an Adverse Reliability Impact” in Requirement R5. We recommend striking “or expected” for simplicity and to avoid the confusion of whose expectation it is. In Requirement R8, “while not IROLs” should be “while not an IROL”. We agree with removing the 30 minute limit in Requirements R9 and R11 and basing the time limit upon the Facility Rating or Stability criteria. In Requirement R10, striking “each” before SOL would improve the clarity of the requirement. In Measurement M1, “nless” should be unless. This may already be correct. The red-lines show “nless” and the clean document shows “unless”. What is the intended difference between Transmission Operator Area in Requirement R5 and internal area in

Requirement R8? Should they be the same and if not why not?
No
We largely agree with the changes but have identified the following specific issues. We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted into the purpose statement. For Requirement R1, it is not clear why focus is on Facility Ratings and Stability Limits rather than SOLs. We suggest using the term SOL instead.
No
We largely agree with the changes but have identified the following specific issues. We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Because of the difficulties experienced by some entities in receiving the RC data specification in IRO-010-1a, we recommend that the implementation of TOP-003-2 Requirement R5 occur a couple of months after the implementation in TOP-003-2 Requirements R1-R4. IRO-010-1a is a parallel standard to TOP-003-2 and the effective date of the distribution of the RC data specification was simultaneous to the effective date of the requirement for the recipients to comply with the data specification. This meant that the RC could provide the data specification on the same date that the recipients had to meet the data specification. Unfortunately, there were some entities expecting to receive the data specification that did not and were concerned about a potential non-compliance. What if an auditor determined the RC should have provided the data specification? Would the entity that expected to receive the data specification be held responsible? By staggering the effective date of Requirement R5, this confusion can be avoided.
No
The VSLS for TOP-002-3 Requirements R1 and R2 could have more levels based on the number of days for which there is not a plan or Operational Planning Analysis.
Group
City Water Light and Power (CWLP) - Springfeild - IL
Shaun Anders
No
R8 requirement to identify "...SOLs which...have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis" is vague and difficult to measure. "Internal area reliability" could conceivable include all SOLs CWLP echoes SERC Operating Committee comments submitted separately: "We suggest that the definition of Reliability Directive should be modified as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or "an event that results in Bulk Electric System instability or Cascading". We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition."
No
R1 should utilize SOL and IROL criteria as opposed to Facility Ratings and Stability Limits criteria for consistency and clarity R1 Rationale language lacks clarity. Poor definition of "process", "tools", and "procedures" could be construed to indicate that a TO must be able to perform analysis internally even when basic non-automated "tools" such as offline power flow software are not available. The intent of "tool" is unclear in general for this instance. If the intent is to capture the use of online

automated tools such a Real-Time Contingency Analysis and ensure that offline analysis capabilities are retained, the language should explicitly include “online automated tools” or “real-time automated tools”
No
R1 and R2 require specifications for data exchange which do not account for the ability of the respondent to meet the specification. As written, the requirement could force a respondent to continue to provide data with such a format, periodicity, or deadline that would be an undue burden to the respondent. All requirements should explicitly stress a mutually agreed plan and R1.1/R2.1 should refer to classes or types of as a qualifier. Likewise, R5 should explicitly state that respondents shall satisfy the obligations within the context of a mutually agreed specification.
Individual
Jason Snodgrass
GTC
No
M4 is misreferencing R2 and R4 and should be corrected as follows: ….”receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R5.”
Demonstrating providing all data specifications for real time operations horizon is very prescriptive in nature and could have unanticipated "compliance documentation" consequences when data or the transfer method is unavailable (e.g., when an RTU goes down).

Please see the attached for additional comments received.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Submitted on behalf of Southern Company

Comment Form for 6th Draft of Standards for Real-Time Operations (Project 2007-03)

Comments on the 6th draft and successive ballot of the standards for Real-Time Operations (Project 2007-03) must be submitted by **January 12, 2012.** If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at 609-947-3673.

Background Information:

In the 6th posting for Project 2007-03, the Real-Time Operations Standard Drafting Team (RTOSDT) has attempted to clarify the proposed changes to the TOP family of standards based on industry comments received for the 5th posting and suggestions made during the Quality Review. Changes made were:

TOP-001-2:

- o Changed the title of the standard to 'Transmission Operations' to better reflect the content of the standard.
- o Based on Quality Review feedback changed the Purpose of the standard to more fully align with the requirements of the revised standard.
- o Revised Requirement R1 to note that a Reliability Directive should be identified as such
- o Deleted 'upon recognition' from Requirement R2
- o Deleted 'all other' from Requirement R3
- o Added Reliability Coordinator to Requirement R5
- o Deleted Generator Operator from Requirement R6 and clarified that the requirement was for 'telemetry equipment'
- o Deleted the 30 minute limit from Requirement R9 and replaced it with references to Facility Rating and Stability criteria
- o Deleted the 30 minute limit from Requirement R11 to correspond with the change in Requirement R9
- o Made a semantic change for clarity to Measure M2
- o Changed the Time Horizons for Requirements R3, R5, and R8
- o VSLs for Requirements R3, R5, and R6 were changed to move away from percentages
- o The language for the VSLs in Requirements R2, R6, & R8 was clarified
- o Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-002-3:

- Revised Requirement R2 to read as a positive statement rather than as a double negative
- Added the term "NERC" as a modifier of "registered entities" in Requirement R3
- Changed the VRF for Requirement R3 to Medium
- Modified the VSLs for Requirement R1
- Based on Quality Review feedback modified the Data Retention section to reflect the current NERC Rules of Procedure.

TOP-003-1:

- Based on Quality Review feedback, the Purpose of the standard has been modified to more fully align with the requirements of the revised standard.
- The bullets under Requirement R1, Part 1.1 have been deleted.
- Added new Requirement R2 to separate out the responsibilities of Balancing Authorities from Requirement R1.
- In response to Quality Review feedback, modified the language in Requirements R3 and R4 to clarify which data the Transmission Operator and Balancing Authority are to distribute.
- Made conforming changes to Measures to reflect changes to the Requirements.
- Based on Quality Review feedback, modified the Data Retention section to reflect the current NERC Rules of Procedure and Drafting Team Guidelines for evidence retention.
- Made conforming changes to VSLs to reflect changes to Requirements.

Other changes:

- The definition of Reliability Directive has been modified by Project 2006-06 to read as follows:

  "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts."

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments: **We suggest the Standard Drafting Team further clarify or define the term "supporting internal area reliability". It is unclear what is meant by this phrase. The standards need to be very clear so as to aid in demonstrating compliance and to show how they enhance reliability.**

   It is unclear whether this standard applies to "next-day" only or if it includes current day / real time assessments as well. We have the following suggestions to add current day / real time, which enhance reliability, and to clarify the standard:

   - **We suggest including "Real-time Assessments" in this standard to clarify Operations Planning and same day operations time horizons (Requirement 8).**
   - **We request that the drafting team review and explain the difference in the time horizons for Requirements 3, 5 and 8.**

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments: **We understand the flexibility that the SDT is attempting to allow in the Requirement, however, in order to reduce confusion and ambiguity which may result in a CAN, and to avoid potential Standards of Conduct issues, we recommend that the term 'all NERC registered entities' be replaced with the operating entities, Transmission Operator, Generator Operator and Load Serving Entity.**

3. The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments: **The applicability of the VSL for R1 and R2 is unclear - is the VSL applicable to the TOP/BA requesting the data or is it applicable to the TOP/BA providing the data? If it applies to the TOP/BA requesting the data we would suggest that the SDT be consistent with the VSLs in IRO-10-1a.**

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☐ No

   Comments: **See the responses to question 3 above**

5. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.

   Comments: **Data retention requirements for TOP-001-2, TOP-002-3 and TOP-003-2 need to align with the expectations of the compliance entity. For instance, the data retention requirements indicate 1 year in some cases and in some cases, the compliance enforcement entities expect to be able to review evidence back to the previous audit.**

Non-binding Poll Results

Project 2007-03 Real-time Operations – TOP-001-2

Non-binding Results	
Non-binding Poll Name:	Project 2007-03 non-binding TOP-001-2
Poll Period:	1/9/2012 - 1/19/2012
Total # Votes:	304
Total Ballot Pool:	373
Ballot Results:	81.50% of those who registered to participate provided an opinion or an abstention; 67.61% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	View
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	View
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba		

1	Empire District Electric Co.	Ralph F Meyer	Abstain	
1	Entergy Services, Inc.	Edward J Davis	Negative	View
1	FirstEnergy Energy Delivery	Robert Martinko		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill	Abstain	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Negative	
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Negative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	View
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	Muscatine Power & Water	Tim Reed	Negative	
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		

1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	View
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Negative	
1	Seattle City Light	Pawel Krupa		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Negative	
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Negative	View
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		

2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Robert Lafferty	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	View
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	View
3	City Water, Light & Power of Springfield	Roger Powers	Abstain	
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Negative	View
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Negative	View
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Negative	View
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Abstain	

3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	View
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock		
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	

4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	View
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li		
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge	Abstain	
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	View
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul A Cummings	Affirmative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	

5	City of Tallahassee	Brian Horton	Affirmative	View
5	Cleco Power	Stephanie Huffman	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	View
5	MidAmerican Energy Co.	Christopher Schneider	Abstain	
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Negative	
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	View
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla	Abstain	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	

5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Redding	Marvin Briggs	Affirmative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Negative	View
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Negative	View
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	View

NERC

6	MidAmerican Energy Co.	Dennis Kimm	Negative	View
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Abstain	
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
8		Edward C Stein		
8		Roger C Zaklukiewicz	Abstain	
8		James A Maenner	Affirmative	
8		Merle Ashton		
8	INTELLIBIND	Kevin Conway	Negative	View
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	California Energy Commission	William M Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Abstain	
9	Utah Public Service Commission	Ric Campbell		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Stacy Dochoda		
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	

10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Non-binding Poll Results

Project 2007-03 Real-Time Operations TOP-002-3

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-03 non-binding TOP-002-3
Poll Period:	1/9/2012 - 1/18/2012
Total # Opinions:	285
Total Ballot Pool:	373
Summary Results:	76.41% of those who registered to participate provided an opinion or an abstention; 71.42% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman		
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	
1	Clark Public Utilities	Jack Stamper		
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba		
1	Empire District Electric Co.	Ralph F Meyer	Abstain	
1	Entergy Services, Inc.	Edward J Davis	Negative	View

1	FirstEnergy Energy Delivery	Robert Martinko		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier		
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Negative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	View
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	Minnkota Power Coop. Inc.	Richard Burt	Affirmative	View
1	Muscatine Power & Water	Tim Reed	Negative	
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins		

1	Portland General Electric Co.	Frank F. Afranji	Affirmative	View
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Negative	
1	Seattle City Light	Pawel Krupa		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Negative	
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	View
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	Alabama Power Company	Richard J. Mandes	Affirmative	View

3	Ameren Services	Mark Peters		
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Robert Lafferty		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	View
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	View
3	City Water, Light & Power of Springfield	Roger Powers	Abstain	
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Negative	View
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Negative	View
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Negative	
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	

3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	View
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock		
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young		
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache		
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	View
4	City Utilities of Springfield, Missouri	John Allen	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		

4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li		
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge		
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	View
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul A Cummings	Affirmative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	View
5	Cleco Power	Stephanie Huffman	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke		
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	

5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Abstain	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	View
5	MidAmerican Energy Co.	Christopher Schneider	Abstain	
5	Muscatine Power & Water	Mike Avesing	Affirmative	View
5	Nebraska Public Power District	Don Schmit	Negative	
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	View
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla	Abstain	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins		

5	Snohomish County PUD No. 1	Sam Nietfeld		
5	Southern California Edison Co.	Denise Yaffe	Abstain	
5	Southern Company Generation	William D Shultz		
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Redding	Marvin Briggs	Affirmative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Negative	View
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Negative	View
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Abstain	
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	

6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter	Negative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	View
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		Edward C Stein	Affirmative	
8		Roger C Zaklukiewicz	Negative	View
8		James A Maenner	Affirmative	
8		Merle Ashton		
8	INTELLIBIND	Kevin Conway	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Negative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	View
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D. Grimm	Affirmative	View
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Non-binding Poll Results

Project 2007-03 Real-time Operations TOP-003-2

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-03 non-binding TOP-003-2
Poll Period:	1/9/2012 - 1/19/2012
Total # Opinions:	304
Total Ballot Pool:	373
Ballot Results:	81.50% of those who registered to participate provided an opinion or an abstention;70.28% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Abstain	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Abstain	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge	Abstain	
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Abstain	View
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	View
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Negative	View
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba		

1	Empire District Electric Co.	Ralph F Meyer	Abstain	
1	Entergy Services, Inc.	Edward J Davis	Negative	
1	FirstEnergy Energy Delivery	Robert Martinko		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Grand River Dam Authority	James M Stafford		
1	Great River Energy	Gordon Pietsch		
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam	Negative	
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Abstain	
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	View
1	MidAmerican Energy Co.	Terry Harbour	Abstain	
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	Muscatine Power & Water	Tim Reed	Negative	
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Abstain	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		

1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	View
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana	Abstain	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	SCE&G	Henry Delk, Jr.	Negative	
1	Seattle City Light	Pawel Krupa		
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	South Texas Electric Cooperative	Richard McLeon	Negative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Robert Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young	Affirmative	
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	View
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	View
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Abstain	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	

2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles Yeung		
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Abstain	
3	APS	Steven Norris	Abstain	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Robert Lafferty	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	View
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	View
3	City Water, Light & Power of Springfield	Roger Powers	Abstain	
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea		
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Negative	View
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster		
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Negative	View
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Negative	

3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	View
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Negative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock		
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Negative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	View

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4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards	Affirmative	View
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li		
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Affirmative	
5	Amerenue	Sam Dwyer	Abstain	
5	Arizona Public Service Co.	Edward Cambridge	Abstain	
5	Avista Corp.	Edward F. Groce	Abstain	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	Chelan County Public Utility District #1	John Yale	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	View
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul A Cummings	Affirmative	View
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Brian Horton	Affirmative	View
5	Cleco Power	Stephanie Huffman	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis		
5	Cowlitz County PUD	Bob Essex	Affirmative	

5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter	Negative	
5	East Kentucky Power Coop.	Stephen Ricker	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Negative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	View
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	View
5	MidAmerican Energy Co.	Christopher Schneider	Abstain	
5	Muscatine Power & Water	Mike Avesing	Negative	View
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	View
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla	Abstain	
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	

5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	View
5	U.S. Bureau of Reclamation	Martin Bauer	Negative	View
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Abstain	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Redding	Marvin Briggs	Affirmative	View
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Negative	View
6	Entergy Services, Inc.	Terri F Benoit	Negative	View
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Abstain	
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm	Negative	View
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View
6	Orlando Utilities Commission	Claston Augustus Sunanon		

6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon		
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet		
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F. Lemmons		
8		Edward C Stein		
8		Roger C Zaklukiewicz	Abstain	
8		James A Maenner	Affirmative	
8		Merle Ashton		
8	INTELLIBIND	Kevin Conway	Negative	View
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	California Energy Commission	William M Chamberlain	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Abstain	
9	Utah Public Service Commission	Ric Campbell		
10	Florida Reliability Coordinating Council	Linda Campbell		
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Stacy Dochoda		
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Name (38 Responses)
Organization (38 Responses)
Group Name (21 Responses)
Lead Contact (21 Responses)
Question 1 (55 Responses)
Question 1 Comments (59 Responses)
Question 2 (52 Responses)
Question 2 Comments (59 Responses)
Question 3 (53 Responses)
Question 3 Comments (59 Responses)
Question 4 (32 Responses)
Question 4 Comments (59 Responses)
Question 5 (0 Responses)
Question 5 Comments (59 Responses)

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Group
Northeast Power Coordinating Council
Guy Zito
No
Requirements R1 and R2 should not be separate. Having them broken out in this manner could potentially put entities in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then Requirement R4 should be broken down into two requirements. Requirement R4 states that information is being requested, AND is available. In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning Analysis as "An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency? The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency does not occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard. Double jeopardy is introduced with TOP-001 R8 and FAC-014 R5.2. Fac-014 R5.2 states "The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area"; while TOP-001 R8 states "Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis."
No
The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, suggest that the requirement should either state the requirement for a process to conduct an Operational Planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement. R1. The Transmission Operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. Requirement R2 uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-014 R5. SOL's that affect a TOP internal area would also affect the RC area. The Drafting Team needs to define the term "internal area reliability" in order to improve the clarity of the standard (see Question 1 comments regarding TOP-001 Requirement R8). Regarding Requirement R3, would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall?
No

TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates the TO, LSE, and Generator Owners to provide this real-time data. These entities provide a wealth of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue. TOP-003 R5 has only a severe VSL. Data providers can provide hundreds if not thousands of points to TOPs. If one RTU goes down is the data provider going to be assessed a severe VSL?
TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard Section on page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for "Reliability Directive" changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an "across the board" usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts." It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Individual
Jonathan Appelbaum
United Illuminating Company
No
R3 phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. Glossary defines emergency as Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. Glossary defines Operation Planning analysis as An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). I do not see the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to effected by an anticipated Emergency. Those TOP's known to be effected are part of the group expected to be effected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. Along the thought the Time Horizon in the Requirement is Operations Planning. I suggest rephrasing this requirement as: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Comment for R8. It seems that double jeopardy is introduced with TOP-001 R8 and FAC-011 R5.2. Fac-011 R 5.2 states The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area; while TOP-001 R8 states R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis.
No
The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, UI suggests the requirement should either state the requirement for a process to conduct an Operational planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement. R1. The Transmission operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. R2: uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-011 R5. SOL's that affect a TOP internal area would also affect the RC area.
No
TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates TO, LSE, and Generator Owners to provide this real-time data. These entities provide a multitude of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear to UI that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.
No
TOP-003 R5 has only a severe VSL. This seems unequitable to the data providors who are responsible for tens of thousands of data points, some redundant. Especially since State Estimators are designed to estimate for bad or missing data.
Individual
Jonathan Appelbaum
United Illuminating
No
R3 phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. Glossary defines emergency as Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. Glossary defines Operation Planning analysis as An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load

forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). I do not see the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to effected by an anticipated Emergency. Those TOP's known to be effected are part of the group expected to be effected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. Along the thought the Time Horizon in the Requirement is Operations Planning. I suggest rephrasing this requirement as: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Comment for R8. It seems that double jeopardy is introduced with TOP-001 R8 and FAC-011 R5.2. Fac-011 R 5.2 states The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area; while TOP-001 R8 states R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis.
No
The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, UI suggests the requirement should either state the requirement for a process to conduct an Operational planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement. R1. The Transmission operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. R2: uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-011 R5. SOL's that affect a TOP internal area would also affect the RC area.
No
TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates TO, LSE, and Generator Owners to provide this real-time data. These entities provide a multitude of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear to UI that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.
No
TOP-003 R5 VSL is only severe. Data providers can provide hundreds if not Thousands of points to TOPs. If one RTU goes down is the data provider going to be assessed a severe VSL.
Individual
Rich Vine
California Independent System Operator
No
R6 requires Balancing Authorities and Transmission Operators to notify "negatively impacted interconnected NERC registered entities" of planned outages. This term is not specific enough to narrow down who must be notified. For instance, with this open-ended wording it could be construed that BAs would have to notify LSEs and DPs in their areas which would be an onerous task. We would recommend staying with "negatively-affected BAs and TOPs." The wording in R9 is confusing and is not specific enough to ensure compliance. In particular the requirement prohibits operation outside any SOL "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based." However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. In addition, under R9 and M9, how will the word "continuous" be defined or measured? This is extremely important to understand because the VSL table states the following as Severe for R9: "The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria." It seems that the effective date should be set much sooner than 24 months following approval since there are basically no new requirements associated with this standard. Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Yes
The ISO supports the changes made in TOP-002-3 but notes that the "Seasonal Assessment" previously required by TOP-002-2 is no longer addressed in the TOP-002-3 wording. Is this an oversight or is this seasonal assessment going to be contained elsewhere?
Yes
The words "and Operational Planning Analyses" should be added to the end of the first sentence in R2 (the Operational Planning Analysis is included in R1). A similar addition should be made to R4.
Individual
Thomas E Washburn
FMPP
Yes
Yes
Yes

Yes
Comments for Project 2007-03 Real-Time Transmission Operations The changes to the TOP Standards are a great improvement over the existing Standards; however, I think because they are so much better than the existing Standards that they should be implemented as soon as possible. I think one year is enough time to make the necessary changes to processes, procedures and documentation. Even more important than the implementation of the new Standards is the deletion of the existing Standards as soon as possible. Some of the existing Requirements are worthless and unenforceable. The SDT has determined that some of the existing Requirements are replaced by new requirements and they will need to be enforceable until the new Requirements are enforceable. However, the SDT has identified some Requirements that are either no longer necessary or covered by existing Requirements or the Functional Model (see mapping document excerpts below): • PER-001-0 R1 • TOP-001-1 R1 • TOP-002-2 R2 • TOP-002-2 R7 • TOP-002-2 R8 • TOP-002-2 R18 • TOP-002-2 R19 Deleting these Requirements does not need to have an implementation period. They can be deleted as soon as approved by FERC with no waiting. TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it never should have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! Also the SDT has identified some Requirements that apply to the Balancing Authority that are either no longer necessary (or even NEVER should have been applicable) or covered by existing Requirements or the Functional Model (see mapping document excerpts below): • TOP-002-2 R1 • TOP-002-2 R5 • TOP-002-2 R6 • TOP-002-2 R10 The SDT states for TOP-002-2 R10: “The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority.” Obvious wrong Requirements like TOP-002-2 R10 should be deleted ASAP. They are a compliance conundrum, and open to compliance fines! From the Mapping Document: PER-001-0 R1 is deleted because “In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator’s authority to issue directives arises out of the Commission’s approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.” TOP-001-1 R1 is deleted because “This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn’t alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the bulk power system have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn’t perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement.” TOP-002-2 R1 is deleted for the Balancing Authority because “The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and must take action per approved EOP-002-2.1, Requirement R6 and thus the Balancing Authority part of this sentence can be deleted. Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities as per their certification as NERC registered entities. “ TOP-002-2 R2 is deleted because “The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted. “ TOP-002-2 R5 is deleted for the Balancing Authority because “The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be ‘in charge’. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model.” TOP-002-2 R6 is deleted for the Balancing Authority because “The part of this requirement dealing with the Balancing Authority is replaced by approved BAL-002- 0 and proposed BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be ‘in charge’. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. “ TOP-002-2 R7 is deleted because “The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-1, Requirement R2 and therefore this requirement is redundant and can be deleted as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority!” TOP-002-2 R8 is deleted because “The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted as all elements of the requirement are now covered in other standards. Voltage and reactive power balance are the responsibility of the Transmission Operator (not the Balancing Authority) and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority!!” TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it should never have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! TOP-002-2 R10 is deleted for the Balancing Authority because “The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority.” TOP-002-2 R18 is deleted because “This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. “ To make matters worse this Requirement is the tier 1 Requirements for actively monitored Requirements for 2012! Which means NERC views this as an important Requirement to reliability. But I agree with the SDT that this Requirement adds NO reliability benefit. TOP-002-2 R19 is deleted because “This is part of an entity's certification and is no longer required in standards. “
Individual
Scott Bos
Muscatine Power and Water
No
Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you can't draw SOLs into the same category as IROLs unless you clearly

indicate these standards only apply to a subset.
No
Issue: The SDT uses a non FERC approved term of “Operational Planning Analysis”, This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval.
No
Issue: There is a great possibility of double jeopardy when R3 and R4 have in part the statement of “…in meeting its NERC-mandatory reliability requirements.” So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non-compliant with any of the unknown “…in meeting its NERC-mandatory reliability requirements” then they would be found non-compliant with this Standard. It is not clear why this Standard is being written with the statement of: “…in meeting its NERC-mandatory reliability requirements.”
Yes
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
No comment.
PacifiCorp would like to express their appreciation to the SDT for their efforts. This consolidation effort has resulted in a more streamlined approach to this set of interrelated NERC Reliability Standards. PacifiCorp would recommend that NERC consider other sets of standards for which such a consolidation effort would be mutually beneficial to NERC and stakeholders, from both a compliance and administrative standpoint.
Individual
Howard Rulf
We Energies
No
R3’s wording is incomplete. It requires informing and states who must be informed but does not state what must be told. The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP’s BA(s) of an Emergency. Should also include the BA informing its RC and TOP(s) R4 It is not clear what emergency assistance a TOP can provide? Most actions would involve moving a generator or shedding load, the few items a TOP can do independently like returning a line from outage, or switching reactive devices should be done as a matter of course. R5 The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP’s BA(s) of an operation resulting in an Adverse Reliability Impact. Should also include the BA informing it’s RC and TOP(s) R6 is overly broad. Every entity in an interconnect can be negatively impacted somehow. The requirement should be focused on the operational entities of the TOP, BA and RC. These are the entities that specify the data that must be made available see IRO-010, proposed TOP-003 from others. Individual asset owners provide data to the operators and when the operators plan an outage they should let the other affected TOP, BA and RC know its to happen. R8: change “have” to “has”. The associated measures should be updated to reflect the above. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.
No
How current should the Operational Planning Analysis be? By definition it can be 12 months ahead. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.
No
R1.4 and R2.4: The deadline must allow time to gather and send the data. If the TOP said immediately, you would be immediately non-compliant. In addition, R2 should include data necessary to perform at least Next Day analysis, even Operational planning Analysis. R5 needs to include the DP. Data Retention: Each bullet states that monitoring is required in accordance with Measures. Measures cannot be requirements.
Group
Southwest Power Pool Regional Entity
Emily Pennel
No
Action is only required by the proposed standards if a real time violation of a previously identified SOL occurs. No action is required in a preventative manner and no action is required as a result of a real time problem that was not identified by the Operational Planning Assessment. R5 should include notifying the RC of anticipated SOL violations. Addition in quotes. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact "or SOL violation" on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.
No
See item number 5 for comments.
Yes

Yes
The standards being proposed are not sufficient to replace the requirements of the 9 standards being retired by this project. The requirements listed below are not covered by the new standards. TOP-001-1 R5. New requirement (TOP-001-2 R11) does not cover "take actions to avoid when possible or mitigate the emergency." Pre-emptive action is an important part of preventing cascading outages. The proposed TOP-001-2 R11 only deals with real time violations. The SDT is relying upon IRO-001-3 being approved in order to retire some of these requirements; however, this has not yet been passed by industry. TOP-002-2 R1. If conditions change on the current day, where in the proposed standards is a new operating plan required to prepare for the next contingency or identify new SOLs? R6. Which of the proposed standards obligate the TOP to continuously plan for the next N-1 event? R13. MOD-024 and MOD-025 (which would replace this requirement) were not approved by FERC in the initial set of standards. A replacement standard MOD-025-2 has been posted for comment, but has not had an initial ballot. TOP-004-2 R1. The proposed TOP-001-2, R7 and R9, only requires IROLs and certain SOLs be respected. The requirement being retired applied to all SOLs. This reduces BES reliability. R4. This covers cases where no Operational Planning Assessment is available to ensure the system is in a safe state. The proposed TOP-002-3 does not include any requirement about when a new study is needed. TOP-006-2 R5., R6., R7. The SDT is relying on the certification process to justify the retirement of these requirements. However, the Certification Process only looks at approved applicable Reliability Standards. If these are retired, these will no longer be reviewed by the Certification Team. TOP-008-1 R2. The current language in TOP-008-1, R2 of "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" is different than the proposed language of TOP-001-2, R7 and R9 "shall not operate outside the IROL (or SOL)". We recommend incorporating the "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" into TOP-001-2 R7. PER-001-0 R1. The existing requirement specifically places the responsibility on the personnel on shift not on the senior management. This does not appear to be covered by any other requirement. PRC-001-1 R2. The obligation to take corrective actions for protection relay or equipment failures is not covered by the proposed TOP-003-2 standard.
Group
NIPSCO
Joe O'Brien
Yes
In R8 consider changing "internal area" to "Transmission Operator Area" In R9 consider clarifying "continuous duration", what is that?
Yes
None at this time
Yes
In R3 & R4 the phrase "in meeting its NERC-mandated reliability requirements" is too open-ended and may be difficult to comply with. This should be more specific; what requirements are these.
Yes
None at this time
None at this time,
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
No
• If the definition of “Reliability Directive” remains, the Definitions of Terms Used in the Standard should note that there is in fact a new or revised definition. ATC agrees with the definition. • Requirement 4 – This should have a control by the Reliability Coordinator to ensure that a Transmission Operator in distress has, in fact, implemented their “comparable emergency procedures”. • Requirement 5 - ATC does not agree with removing the BA from this requirement since they make note that it will be addressed in another, “proposed” requirement as stated in the mapping document. • Requirement 7 - Real-Time EMS representation of IROL Tv, will require an unidentifiable amount of resources. • Requirement 9 - SOL’s should have a time requirement. Also, they should not be raised to the level of IROL’s as may be insinuated by this requirement if they are discretionary, as noted in Requirement 8. • Requirement 11 - If this requirement entails the issuing of a “Reliability Directive”, it should be stated as such.
No
Requirement 1 - Granted, if the rationale does not mandate “how” an analysis is completed, a better requirement of the “what” should be stated. If this analysis base-case, N-1, is unilateral by the TOP, without iteration with the BA, then should the process be documented?
No
In the introduction to this question, the Standard number should be corrected to TOP-003-2. Requirement 1- A data specification must have bounds. There is nothing that would preclude a request for data that is not achievable yet is mandated to be satisfied by Requirement 5. Requirement 1, sub-Requirement 1.2 may never be arrived at given the former.
None
ATC feels this project has diminished a good base of existing standards, and introduced ambiguity, and vagueness. Additionally, we feel certain key aspects of the current standards were removed for example, “Clear, decision making authority” from System Operators, and the need for “Uniform Line Identifiers”, which is not in the interest of Reliability.
Individual
Jeff Longshore
Luminant Energy Company, LLC
Yes

Yes
No
TOP-003-2 as currently written does not provide any recourse for the entity receiving a data request if that entity feels the data request is unreasonable either in content or timing or if the entity does not have the data available to submit. As such I would recommend modify R5 as follows: R5. Each……shall satisfy the obligations of the documented specification for data. R5.1. If the entity receiving the data request cannot provide the requested data either in content or timing then the entity receiving the data request shall notify the requesting entity and provide a reason for not providing the data.
No
The VSL for TOP-003-2 R5 places a more stringent severity level on the entities receiving the data requests than it places on the entities that are responsible for creating the data requests. As such, I would suggest changing the VSL for TOP-003-2 R5 to the following: Lower: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy one of the obligations of the documented specification for data. Moderate: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy two of the obligations of the documented specification for data. High: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy three of the obligations of the documented specification for data . Severe: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy four or more of the obligations of the documented specifications for data.
Group
Lincoln Electric System (LES)
Eric Ruskamp
No
R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included a provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? R8 is unclear as currently drafted. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation.
Yes
No
Please refer to comments submitted by MRO's NERC Standards Review Forum for LES' concerns related to TOP-003.
No
The word "affected" should be added to the Moderate VSL for TOP-001-2 R3 following "…known or expected to be affected by an actual…".
Group
Progress Energy
Jim Eckelkamp
No
Progress, while supporting what we believe is the overall intent of this Standard revision, cannot support an affirmative vote on TOP-001-2. Progress appreciates the efforts of the SDT and offers the following suggestions: In R8 it remains unclear what is meant by the phrase "supporting its internal area reliability." Clarity and unambiguous language is needed here so that entities can clearly understand and comply with the requirement. Progress understands from reading the most current "Consideration of Comments" that the Standard Drafting Team left this phrase intentionally undefined; however, the inclusion of this phrase means that in an audit scenario there could be a disagreement about what "supporting its internal area reliability" means. This has the potential to negatively impact the compliance position of the Transmission Operator. In R9 it is unclear what is meant by a "continuous duration that would cause a violation…" Some entities may have facility ratings that are time based, while other entities take the position that the exceedance of a facility rating for any amount of time means an SOL violation. A suggested change in wording would be to simplify the requirement to read "Each Transmission Operator shall not operate outside any SOL indentified in Requirement R8 that would cause a violation of the Facility Rating or Stability criteria upon which it is based." Progress suggests changing R10 to read "Each Transmission Operator shall inform its Reliability Coordinator of the mitigation actions it has taken or directed to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded." The current draft language implies that the TOP must only inform the RC of "…its actions…" Progress suggests switching the order of the current R10 and R11; from reading the most current "Consideration of Comments" it seems that the actions required in R8-R11 are intended to be sequential. Progress suggests that switching the order of the current R10 and R11 would make it easier for a reader to understand that these are intended to be sequential actions.
Yes
A definition of "internal area reliability" is needed
Yes

Please include "operational Planning Analyses" in R2 as you have in R1.
Group
Bonneville Power Administration
Annie Lauterbach
No
Comments: Given the potential uncertainty regarding the 30 Minute Rule, BPA suggests adding more clarity to the standard TOP-001-2 as the new draft could be interpreted to mean that one would need to get the flows below the SOL immediately. BPA believes this is not practical because it takes a definite amount of time to change schedules, move generation, or perform other actions in order to reduce loadings on facilities. BPA believes the new draft should include guidance as to how much time the BA or Transmission Operator would be allowed in order to reduce flows when there is an SOL violation. BPA suggests that more clarity be provided and/or the 30 minute rule be added back to the standard.
No
Given the potential uncertainty regarding how many day ahead studies may be required, BPA suggests adding more clarity to the standard TOP-002-3. BPA recognizes that various regions experience peak operations at different times of the day, anticipated generation patterns shift over the course of the day, and transmission facilities come in and out of service for planned work at various times throughout the day. Hence, due to these multiple shifts in forecast system conditions, it is unclear whether more than one study is required to meet the requirements of this standard.
Yes
BPA is in support of standard TOP-003-1, due to the importance of being able to receive data.
Individual
DAVID DOCKERY
Associated Electric Cooperative, Inc.
Yes
R3 Guidance Add: A Guidance Section for Requirement R3 clarifying “anticipated Emergency” - AECI believes the SDT should draft guidelines as to what “anticipated Emergency” means within this requirement. That guidance should also caution against dumping information (data-overload)upon neighboring parties, for trivial impacts to their system. Rationale: In earnest to avoid non-compliance with R3, entities could blast their neighbors with all changes, regardless of impact, and then the purpose of this requirement will be lost.) R6 Requirement wording Change: “negatively impacted” To: “known negatively impacted” Rationale: While 1st hand affected parties are likely known, secondarily affected parties might pose a compliance problem. R8 Guidance Add: An R8 Guidance section Rationale: AECI’s understanding is that our providing our RC with AECI’s most-limited-element equipment seasonal operating limits and short-term limits, where applicable, meets this requirement. If we are wrong, then additional guidance is definitely necessary.
Yes
R1 Rationale Change: Rework or remove entirely Rationale: The R1 Rationale section does not match the R1 requirement as currently worded, and frankly is impossible, within the timing constraints of next-day analysis. (Example: PSS/E is technically a tool for steady-state network analysis. Without that tool, or a similar network-analysis tool being available, such analysis would be impossible by hand.) R3 Requirement wording Change: “in the plan(s)” To: “in the N-1 contingency-related plan(s)” Then Append: “, N-2 related contingency-plan(s) should be omitted unless highly plausible.” Rationale: This recommended change seeks to avoid information overload on neighbors, while still encouraging more in-depth near-term contingency planning.
Yes
TOP-003-1 R1, R2, and R3 Guidelines Add: Guidelines Section - These requirements are all written as highly TOP-centric and BA-centric, without regard to the confusion and work-load a single published plan could cause small entities. If hundreds or perhaps thousands of data-points are cited within a uniformly circulated plan, yet some entities provide only one or two obscure points within that plan, then the TOP or BA is being unnecessarily inconsiderate, and should have appropriately filtered that request for their audience. Rationale: Very large TOPs or BAs would benefit from being reminded that they need to consider their audience when sending out plans as data-requests to small entities. There is no need to overwhelm smaller entities with a lot of unrelated data, or data that does not seem to match their own identifiers. We can do better.
No
TOP-001-2-R1 VSL Change: “unless such action would violate” To: “and such action would have violated” Rationale: State the issue rather than recite the requirement. TOP-001-2-R8 VSL Change: “whichever is less” To: “whichever is greater” Rationale: Intent TOP-001-2-R10 VSL Change: “has been” To: “had been” Rationale: grammatical TOP-002-3-R1 Lower VSL: Duplicate Severe VSL wording then append “, on one day within a calendar year.” TOP-002-3-R1 Moderate VSL: Duplicate Severe VSL wording then append “, on two non-consecutive days within a calendar year.” TOP-002-3-R1 High VSL: Duplicate Severe VSL wording then append “, on three non-consecutive days or two consecutive days within a calendar year” TOP-002-3-R1 Severe VSL: Append: “, on four or more days, or three consecutive days within a calendar year.” TOP-002-3-R1 VSL changes Rationale: Eliminate zero-defect expectation TOP-002-3-R3 VSL Change: “of the NERC” To: “, whichever is greater, of the NERC” Rationale: precision and alignment with wording in TOP-01-2 R8 VSLs.
Group
ISO/RTO Standards Review Committee
Albert DiCaprio
No
Instead of using ‘its’ TOP in R1 we suggest using ‘a’ TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation.

Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
No
Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Yes
No
TOP-001-2, R3 Moderate VSL – the word "affected' has been omitted and needs to be inserted. TOP-003-2, R1 & R2 – The use of the term 'element' in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 – The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn't this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Individual
Michael Falvo
Independent Electricity System Operator
Yes
Yes
We assess that the industry's comment on R3 regarding the need to inform all NERC registered entities identified in the plan(s) was due to the absence of a requirement to identify these entities. We therefore suggest to revise Requirement R2 to drive home the need to identify registered entities that are included in the plan(s) to operate to within IROL and SOL, and set the stage for R3: Each Transmission Operator shall develop a plan, and identify the entities that will be required to implement actions, to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
Yes
We agree with the addition of R2, but have a concern over Measure M2, which says: M2: Each Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R2. The wording "dated, current, in force" does not reflect what's in the requirement R2, and is not necessary. This wording pertains to the data retention requirement, which is already included in the second bullet in Section D, 1.3 – Data Retention: "Each Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit." We suggest to remove this wording from M2.
Yes
Group
FirstEnergy
Sam Ciccone
Yes
Yes
Yes
Yes
FE has the following comments and suggestions: 1. In the mapping document, it shows that PRC-001-1 R2 will be replaced by the new TOP-003-2 R5. However, we do not see a new version of PRC-001-2 posted. Also, the

implementation plan makes no reference to PRC-001. 2. The mapping document does not seem to be referencing the correct version of TOP-005 (should be Version 2a). Also, the mapping document is not referencing the correct requirement for TOP-006-1 R4 (the RC should not be shown as applicable).
Individual
Robert Roddy
Dairyland Power Cooperative
Yes
Concern re R5. The determination of when an operating condition could be "expected to result in an Adverse Reliability Impact" would be difficult and ambiguous.
Yes
No
R1 and R2 refer to "A periodicity for providing data" and "The deadline by which the respondent is to provide the indicated data". What if this specification is unreasonable? To address this concern, DPC suggests adding the words "mutually agreeable" as was used in reference to the format specification.
Yes
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
No
R2 - This requirement requires the BA, GOP, and LSE to notify the TOP if it cannot comply with the Reliability Directive. (Comment) – Should include the language that the entity is not able to comply with the Reliability Directive due to violation of safety, equipment regulatory or statutory requirements. R7 – This requirement requires that the TOP not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL (Comment) – Should the language in the requirement also include the reference to SOLs since WECC does not have IROLs? R8 – This requirement requires the TOP to inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis (Comment) – Remove “which, while not IROL” from the requirement language and add “that” before “have been identified”. This would make the statement more clear. R9 – This requirement requires that the TOP not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. (Comment) – Define Continuous. What would constitute a violation? 5 minutes, 10 minutes? In some cases corrective action requires participation and/or direction from the Reliability Coordinator and this could take up to 30 minutes. Recommend leaving the 30 minute duration in place. (Comment) – Recommend referencing R7 if the SOLs are included in the requirement. R10 – This requirement requires the TOP to inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. (Comment) – the language should include the reference to R7 if the SOL is included in the requirement. (Comment) – Recommend including time frame for notification to the Reliability Coordinator to include “30 minutes or less” R11 – This requirement requires the TOP to act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s Measures or of an SOL identified in Requirement R8. (Comment) – Since only the Reliability Coordinator has the authority to direct others to take action; should the language be revised in the following manner; “The TOP shall take action to mitigate both the magnitude and duration of exceeding an IROL or an SOL as identified in R7 and R8 that occur within its TOPs area. The TOP shall appeal to the Reliability Coordinator to direct other TOPs in mitigating both magnitude and duration on interconnected facilities on the Bulk electric System”.
No
R1 – This requirement requires the Transmission Operator to have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions (Comment) - Recommendation that the requirement language be changed to “Each TOP shall perform the required Operational Planning Analysis for Next-Day Operations to assess if the Next-Day Operations Plan will exceed any of its Facility and/or stability limits under normal or emergency conditions”. R2 – This requirement requires the Transmission Operator to develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 (Comment) Recommend that the language be revised for clarity to state the following; “The TOP shall develop a plan to operate within established IROL and SOLs according to the Operation Planning Analysis performed for its Next-Day Operation in Requirement 1. R3 – This requirement requires the TOP to notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) (Comment) – Recommend revising the language in the requirement to state the following; “The TOP shall notify all affected NERC Registered entities of possible impacts identified in its Operational Planning Analysis for its Next-Day Operations in Requirement 1. M2 – The measurement requires the TOP to have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement (Comment) – Revise the Measurement to state the following; “The TOP shall have evidence that it developed a plan to operate within established IROL or SOLs supporting its internal reliability area as a result of its Operational Planning Analysis performed”. M3 – Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records. (Comment) – Revise the measurement to sate the following; “The TOP shall provide evidence that it notified affected NERC Registered Entities as being impacted in the Operational Planning Analysis related to its Next-Day plan. Such evidence shall include but not be limited to dated E-Mails, Operator Logs, or Voice Recordings. Data Retention – Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for

analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records. (Comment): The time frames appear to be pretty specific for the data retention. However when will the entity know that it has to save the evidence farther back than the set time frame. Would it not be better to have the Data Retention language require the entity to save all evidence back 12 months and to save any evidence related to a system disturbance/event?
Yes
Yes
None
Individual
Kathleen Goodman
ISO New England Inc.
No
Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
No
Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Yes
The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
No
Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
No
Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Yes

No
TOP-001-2, R3 Moderate VSL – the word “affected’ has been omitted and needs to be inserted. TOP-003-2, R1 & R2 – The use of the term ‘element’ in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 – The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn’t this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
The definition of Reliability Directive is contained in COM-002-3 and that standard hasn’t been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one’s inability to provide notice. If each function needs to be separate, then they should break out R4 into two requirements. Who’s to say that the information is requested AND available? In TOP-001-2 R3 the phrase “known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis” is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day’s operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP’s expected to affected by an anticipated Emergency. Those TOP’s known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn’t this create an opportunity for broad interpretations of what is permissible and what’s not? It also allows for inconsistent treatment. An auditor’s view might be very different from an entity’s view. Also, regarding TOP-001-2 R6, which states “Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.” This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator’s to the entities within the affected other Reliability Coordinator’s footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to “drill down” and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term “internal area reliability” in order to improve the clarity of the standard.
No
Comments: In Requirement R2 the Drafting Team needs to define the term “internal area reliability” in order to improve the clarity of the standard. Regarding Requirement R3: Would notifying GO’s of “their roles” in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall? Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.
Comments: TOP-001-2 is referencing a NERC definition for “Reliability Directive” which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of “Reliability Directive” would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board” usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.” It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Individual
Michelle R D'Antuono
Ingleside Cogeneration LP - Occidental Chemical Corporation
Yes
From the GO/GOP perspective, Ingleside Cogeneration LP believes that the SDT has captured the appropriate circumstances for when a Reliability Directive is issued and identified – and the circumstances under which it may be not be possible to accommodate one.
Yes

Yes
Although we would prefer to see a consolidated RC-BA-TOP data specification, Ingleside Cogeneration LP agrees that TOP-003-1 is a good first step in that direction. Any help the SDT can provide to reduce overlap in data requests and to drive to a common format is appreciated.
Yes
Ingleside Cogeneration LP believes that the requirements applicable to a GO/GOP carry VRFs, VSLs, and Time Horizons consistent with those assigned to similar requirements.
Individual
David Thorne
Pepco Holdings Inc
No
PHI supports the comments provided by the ISO/RTO Standards Review Committee.
No
PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Yes
No
PHI supports the comments provided by the ISO/RTO Standards Review Committee.
PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Group
Dominion
Connie Lowe
Yes
Yes
No
If this question was meant to refer to TOP-003-2, then Dominion offers the following comments: M5 reads “Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.” Since R2 was added, Dominion suggest M5 should read as “receiving a data specification in Requirement R3 or R4 shall make available evidence that is has satisfied the obligations of the documented specifications for data in accordance with Requirement R5....”.
Yes
Page 1 and Page 15 of the Violation Risk Factor and Violation Severity Level Assignments document, titles reads; Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-2, TOP-003-2:, Dominion suggests changing TOP-002-2 to TOP-002-3.
Individual
Mahmood Safi
Omaha Publc Power District
No
OPPD is concerned with Requirements (R8 and R9) related to System Operating Limits (SOLs). We would like to ask the SDT to clarify what the word “continuous duration” means in terms of timing. We understand the “continuous duration” is based on Facility Rating or Stability criteria, however, without any defined time frame, the term “duration” would be subject to variety of interpretations. OPPD supports a time window to allow TOP to return from SOL similar to IROL Tv.
Yes
No
OPPD is requesting clarification on operational data requirements (R1 and R3) related to “documented specification for the data necessary for it to perform…” What the document should include that is specifying operational data request from or to other Transmission Operators. Additionally, how often operational data specification document should be provided/updated to or from other Transmission Operators.
Yes
Individual
David Burke
Orange and Rockland Utilities, Inc.
No
Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow

entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then they should break out R4 into two requirements. Who's to say that the information is requested AND available? In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard.
No
Regarding Requirement R3: Would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall? Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.
Comments: TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for "Reliability Directive" changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an "across the board" usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts." It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Individual
Joe Petaski
Manitoba Hydro
No
-R1 - Manitoba Hydro suggests that the first instance of 'identified' in R1 be removed as it is redundant given that R1 already specifies that the Reliability Directive is 'identified as such'. As drafted, the standard suggests that there is a difference between an 'identified Reliability Directive' and a 'Reliability Directive'. -Data Retention (1.3) – The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified logs, recordings and emails, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. This comment applies to TOP-001-2, TOP-002-3, and TOP-003-1.
No
-R1 - Given that an Operational Planning Analysis is itself an assessment of planned operations (i.e. the definition of Operational Planning Analysis is 'An analysis of the expected system conditions for the next day's operation…') it is unnecessary to state that the Operational Planning Analysis must allow an assessment of planned operations. Accordingly, Manitoba Hydro suggests that the phrase '...that will allow it to assess…' be replaced with "assessing".
No
-M1 – This measure goes beyond the requirements of the standard, as there is no requirement for a specification document to be dated. Manitoba Hydro suggests either striking 'dated' from M1 or adding the requirement to have a 'dated documented specification' to R1. -M2 – Same comment as M1. Manitoba Hydro suggests either striking 'dated' from M2 or adding the requirement to have a 'dated documented specification' to R2. A -R3 - For consistency with R1 and overall clarity, Manitoba Hydro suggests changing the wording of R3 to 'Each Transmission Operator shall distribute its documented specification developed in accordance with R1 to those entities that have data required by the Transmission Operator to support its Operational Planning Analysis and Real-time monitoring '. The VSL for R3 should

be changed accordingly as well. -R4 - For consistency with R2 and overall clarity, Manitoba Hydro suggests changing the wording of R4 to 'Each Balancing Authority shall distribute its documented specification developed in accordance with R2 to those entities that have data required by the Balancing Authority to perform its Real-time monitoring'. The VSL for R4 should be changed accordingly as well.
No
-TOP-002-3 R3 VSL - The wording of the VSL is unclear. Manitoba Hydro suggests changing the wording of the VSL as follows (the severe VSL of TOP-002-3, R3 is provided as an example): 'The Transmission Operator did not notify either four or more NERC registered entities, or more than 15% of the NERC registered entities identified in the plan(s) as to their role in the plan(s). '
Group
LG&E and KU Serivces
Brent Ingebrigtson
No
LG&E and KU Services believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
Yes
No
LG&E and KU Services do not believe that data/evidence retention requirements should be modified by the Compliance Enforcement Authority. This potentially will result in different data retention requirements across regions. A Compliance Enforcement Authority should enforce only what is written within the standard and not have the option of expanding the requirement. 4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.
Individual
Dana Showalter
E.ON Climate & Renewables
No
ECRNA appreciates the efforts of the drafting team in eliminating duplicative requirements and efforts, as this is an important part of developing clear and concise standards. However, we are concerned about the end result of an unbounded data specification. Although requirements R1 through R4 are directed toward the Balancing Authority and Transmission Operator, these requirements have a direct impact on the other applicable entities. The lack of guidance to and expectations of the data and format could and most likely will lead to a wide range of data specifications from the multitude of Balancing Authorities and Transmission Operators in North America. Entities that own or operate facilities in multiple regions and work with many BAs and TOPs may have difficulty responding to each individual specification's needs, including timeframe, and format. Also considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable. In addition, the sub-requirements to R1 and R2 could be written more clearly to identify who the TOPs and BAs are expected to mutually agree with and request information from. One can assume the applicable entities listed in the standard, but explicitly stating this within the standard is a better method and ensures entities are provided an opportunity to provide input in the data specification format.
No
Considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable.
Individual
Don Jones
Texas Reliability Entity
No
•In R1, the phrase "and identified as such" is redundant and unnecessary in that "identified" already exists within the sentence. Furthermore, the addition of the word "identified" or phrase "identified as such" inserts undue ambiguity and complication, and we are concerned that the "identified" concept will actually provide more opportunities for miscommunications during tense situations. •In R1, we are concerned that "Directive" is being proposed with descriptive terms (e.g., "reliability"), and if the descriptive terms are not used explicitly an entity may not be compelled to act accordingly (also may provide leverage for a perceived loophole in compliance activities that could be exploited—"I was unaware it was a {insert descriptive term} Directive"). •There should be a time frame associated with requirement R2. Perhaps add "within the timeframe determined for the Directive being issued" to end of sentence. Also, we suggest removing "identified" from requirement R2 (see comments on R1). •There should be a time frame associated with the communication required by Requirement R5. •R5 should explicitly include IROL, SOL, and Stability Limit violations in the examples since the proposed definition of Adverse Reliability Impact implies instability and Cascading outages. •We suggest rewriting R5 as follows: "Each Transmission Operator shall inform its Reliability Coordinator and other affected Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas within a timeframe that is sufficient for the RC and affected TOP's to respond to the system condition, unless conditions do not permit such communications. Such operations may include, but are not limited to, Interconnection Reliability Operating Limit (IROL) violations greater than Tv, System Operating Limit (SOL) violations, Stability Limit violations, relay or equipment failures, and changes in generation, Transmission, or Load." •In R9, the use of "continuous duration" in the revised language is confusing and should be removed. It would be better to clearly rely on the other standards that relate to identifying IROLs and SOLs (including duration limits), which may have

multiple time limits associated with various operating conditions. We note that an SOL may not be based on a single Facility Rating but may actually be a group of Facilities aggregated into a single limit. We suggest saying: “for a continuous duration that would cause a violation of the Facility Rating or Stability criteria, including duration, upon which it is based”.
Yes
No
•Regarding R1, we are concerned that the proposed requirement gives each TOP too much latitude to determine what data it considers necessary. This may cause confusion due to significant differences in data specified by different TOPs and the ability of TOPs to unilaterally change their data specifications. We would prefer that the standard include a basic list of data to be included in the specification. •The reference to “mutually agreeable format” in R1 part 1.2 is problematic because it allows the respondents to interfere in the TOP’s data collection process. The TOP should be allowed to dictate a reasonable format for data submission. •In R2, we are opposed the removal of “Operational Planning Analyses” (OPA) for a Balancing Authority in this requirement, because the BA is “the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time.” A BA should create a documented specification for the data necessary for it to perform an OPA just as a TOP does. •The reference to “mutually agreeable format” in R2 part 2.2 is problematic because it allows the respondents to interfere in the BA’s data collection process. The BA should be allowed to dictate a reasonable format for data submission. •In R3 we suggest changing “operating analysis” to “Operational Planning Analysis,” which is a more precise term for what appears to be intended. The same change should be made in Measure M3. •In R4 we suggest adding “Operational Planning Analysis,” to be consistent with our comment that R2 should require “Operational Planning Analysis” data in the BA’s data specification. •In the Measures, please check and correct the references to Requirement numbers – some references are to the wrong requirements. •Under Data Retention, in the 4th bullet starting with “Each Balancing Authority…”, the phrase “and operating analysis assessment processes and” should be struck because it does not align with requirement R4 as currently written. However, we support adding “Operating Planning Analysis” in R4, and this data retention reference should be consistent with the requirement.
No
•Regarding the VSL for TOP-001-2 R5, we suggest that it be based on a percent of applicable TOPs rather than number of TOPs, which would accommodate various sized entities. •Regarding the VSLs for TOP-001-2 R9 and R11, we recommending adding a time duration reference relating to SOL violations, even if it is not a definite number of minutes. •Referring to the VSLs for TOP-003-2 R1, there are only four elements listed, so the reference to “four or more” is nonsensical. Also, there is no difference between omitting four elements and not providing a documented specification at all. Finally, the four listed elements do not appear to have equal importance – perhaps the VSL levels should be assigned based on which elements are missing.
•Referring to the posted “Issues Database,” under Order 693 ¶ 1604/1608, the red-lined language is not actually in the referenced requirement. Does the drafting team contend that the proposed requirements satisfy this FERC directive? •Referring to the posted “Issues Database,” under Order 693 ¶ 1636 (TOP-004), this document suggests that a 30-minute limit is contained in the requirements, but that limit is not in the language that is now posted. Does the drafting team contend that the proposed requirements satisfy this FERC directive? In general, NERC needs to make sure the Issues Database is consistent with the latest draft of the requirements. •The VRF/VSL Assignment Document needs to be cleaned up. There are numerous references to incorrect requirement numbers. On page 3, TOP-001-2 Requirement R3 is struck from the list of “High” VRFs, but it is assigned a high VRF in the posted standard. Also, the title of TOP-001-2 is stated incorrectly in this document (at the beginning).
Individual
Scott Berry
Indiana Municipal Power Agency
no comment
no comment
No
IMPA believes that the entities (Transmission Operator and Balancing Authority) should be required to create a documented specification that lists exactly what the entities (in R5) need to provide to them to meet the requirement and not be allowed to say that “it is in our manuals and/or agreements.” When the Transmission Operator and/or Balancing Authority only references their manuals, it is up to the entity (in R5) to read the manuals that are referenced and then try to come up with a documented specification listing on their own which may or may not include everything that is required by the TO or BA which makes the current draft standard’s language very ambiguous. IMPA is not objecting to these entities using manuals as long as a specific documented specification is created and distributed that does more than just list the name of manuals. The documented specifications need to be detailed in what is required from entities to aid in preventing possible non-compliance issues due to an entity missing an item in a manual or including unnecessary items due to being left to their own interpretations.
no comment
No other comments
Individual
Rich Salgo
NV Energy
Yes
Yes, however, there are a few points to note: Part A, Section 1 continues to title this standard as "Coordination of Transmission Operations, while the header of the Standard was changed to simply "Transmission Operations". The requirements R6 and R8 appear to be outside the realm of real-time operations, R6 dealing with planned outages of telemetry, comm, and control equip, and R8 dealing with communication of SOL's or other limits. It is confusing to mix in Operations Planning type requirements in a standard that otherwise deals with real-time grid operations. Suggest relocating these two to the Operations Planning Standard, TOP-002-3.
Yes

Yes
In the re-draft of these three standards, TOP-001, -002, and -003, we seem to have lost the concept of Planned Outage Coordination for BES facilities (a whole Standard was devoted to the process). In viewing the mapping document, it is stated that the requirements for such outage coordination that used to reside in TOP-003-1 are now replaced by R1 and R2 of TOP-003-2. If this is the case, then all of the activities of outage coordination are to be encapsulated in the clause "documented specification for the data necessary for it to perform its required Operational Planning Analyses..." While it may be covered in this extremely broad clause, the SDT nevertheless gave prominence to the coordination of telemetry outages within a specific requirement R6 of TOP-001-2. If telemetry outages have a separate requirement, then shouldn't planned outage coordination of BES facilities rise to the level of importance that would merit its own requirement?
Individual
Gregory Campoli
New York Independent System Operator
No
Communications must be a well defined, consistent and established process to promote clear and accurate communications between operators for both normal and emergency conditions. This standard could be interpreted as to require an extra phrase during emergencies that would unnecessarily complicate communications. The requirement is reasonable if the identification of a 'Reliability Directive' may be done in a policy or procedure that is communicated to the BA, GOP, DP or LSE as a communication protocol that addresses normal and emergency communications. Otherwise requiring different verbal communication protocols for normal or emergency conditions will add a level of risk currently not observed.
Individual
Martin Bauer
US Bureau of Reclamation
Yes
Yes
No
The language change in R1 has not been incorporated into the sub requirements. The requirement R1 was modified to eliminate the second party. A mutual agreement is required in R 1.2 but only party is listed in R1. The language should specify that the TOP is to coordinate its data requests with the appropriate entities and seek mutal agreement on the format.
Yes
Individual
Alice Ireland
Xcel Energy
No
R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity informs its Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. We would like to see additional clarification to clarify “equipment”, suggest using “equipment limitation” or “equipment rating” R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. This requirement should be modified so as not to place the burden on the assisting entity to demonstrate that the requesting entity has implemented “comparable emergency procedures”. Suggest the following language: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment ratings, regulatory, or statutory requirements. R5. Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. This requirement appears to duplicate PRC-001-1 R2 and R5. It is assumed, but cannot be verified that those requirements will be eliminated in a future approved version of that standard. R9 - We appreciate the drafting team’s efforts. However, we are still concerned that R9 will not allow the Transmission Operator the flexibility to identify the best SOL recovery approach, without incurring a violation of the requirement. Instead, the TOP may be forced to shed load in order to avoid violating the requirement. This is not ideal, especially when the situation could be mitigated successfully with alternative measures. It is not clear if an entity is allowed to use an RC-approved contingency plan to mitigate a situation that would cause a Facility Rating violation (i.e. the Facility Rating is the SOL), without also incurring a violation of R9. To further explain, if an entity foresees exceeding an SOL in its OPA, and obtains approval from the RC on their proposed contingency plan (which includes a Facility Rating violation), will that entity be considered in violation of R9 once the exceedance occurs and the contingency plan is implemented? R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. This requirement should

specify a sustained period which establishes when it is considered that the entity has returned below the limit (or some other value so as to not misconstrue momentary recoveries as meeting this requirement).
Yes
No
Applicability – why are Distribution Providers not subject to this standard? Is it possible that a TOP or BA may need information form a DP to perform an "OPA"? "Mutually agreeable" in 1.2 should be removed. The TOP and BA should work with the subject entities, however stating that something must be mutually agreed upon could create delivery and acceptance of data in a less than desired form solely to meet the words of the requirement.
There is reference in each draft standard to deleting some requirements from PRC-001 but those proposed changes are not show in any proposed drafts or implementation plans (only 1 PRC-001 requirement is listed in the implementation plan).
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst has the following comments for consideration: 1. Definition of Reliability Directive - ReliabilityFirst believes there could be a possible issue with the definition of "Reliability Directive" being developed and approved via another drafting effort (i.e. Project 2006-06). In the hypothetical situation where the TOP-001-2 standard is approved and the definition of "Reliability Directive" is drastically changed through the Project 2006-06 effort, there could possibly be a disconnect between the TOP-001-2 requirements and the "Reliability Directive" definition. Also, ReliabilityFirst recommends adding a parenthetical "(e.g. IROL or SOL violations)" to the end of the definition for further clarity. 2. R2 – There is no time qualifier specified in R2 dealing with the timeframe in which the applicable entity has to inform its Transmission Operator of its inability to perform an identified Reliability Directive. ReliabilityFirst recommends the SDT consider adding language to include a timeframe for the entity to inform the Transmission Operator (such as one hour). Absent any specified timeframe, an applicable entity could hypothetically inform its Transmission Operator of its inability to perform an identified Reliability Directive 30 days after the Reliability Directive was issued, and still be compliant based on the current words of the requirement. 3. R4 – The term "emergency" is used within this requirement and ReliabilityFirst seeks clarification on whether this is referring to the NERC definition of "Emergency" (as defined in the NERC Glossary of terms)? If so, this term should be capitalized. 4. R5 - The last sentence in R5 is not really a requirement, but rather a measure on how to comply with the requirement. ReliabilityFirst recommends deleting the last sentence of R5 and incorporating it into the corresponding Measure. 5. R6 – ReliabilityFirst recommends removing the term "negatively impacted interconnected NERC registered entities" and replace it with the associated functional entities (e.g. Balancing Authority, Generator Operator, etc.). 6. R8 – ReliabilityFirst recommends removing the term "while not IROL's" from R8. SOL is a NERC defined term and the extra qualifier is not needed. 7. R10 and R11 – ReliabilityFirst recommends swapping the order of R10 and R11. From a chronological standpoint, the Transmission Operator will "act or direct others to act, to mitigate…" (R11) prior to "informing its Reliability Coordinator of its actions" (R10). 8. Data retention – ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the last sentence states "the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.
No
ReliabilityFirst has the following comments for consideration: 1. R1 – ReliabilityFirst recommends removing the rationale box from the standard. ReliabilityFirst believes this is not really the rationale for the requirement but rather explains how to measure (show evidence) for the requirement. 2. R2 – ReliabilityFirst recommends deleting the following words from the requirement, "which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1". ReliabilityFirst believes this language does not add anything to the requirement. 3. R2 and R3 – R3 requires the Transmission Operator to notify all NERC registered entities identified in the plan(s) but there is no corresponding requirement for the Transmission Operator to identify NERC registered entities in their plans. ReliabilityFirst recommends incorporating this concept into R2. 4. Data retention – ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the last sentence states "the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.
No
ReliabilityFirst has the following comments for consideration: 1. R1 and R2 – ReliabilityFirst recommends changing the phrase "shall create…" to "shall have…" in R1 and R2. 2. R1 and R2 – ReliabilityFirst recommends changing Part 1.2 and Part 2.2 to state "A format". ReliabilityFirst believes it may be difficult to audit and enforce the phrase "mutually agreeable". 3. R3 – ReliabilityFirst seeks clarification on the term "operating analysis assessment" used in R3. Is this language referring to the Transmission Operators Operational Planning Analyses as required in R1? If not, can the SDT clarify what the phase "operating analysis assessment" is referring to? 4. R3 and R4 – ReliabilityFirst seeks clarity on what the phrase "NERC-mandated reliability requirements" is referring to? Is it referring to FERC approved NERC standard requirements or does it encompass NERC Directives, CANs, NERC bulletins, etc. as well? 5. R3 and R4 – R3 references "those entities" and R4 just references "entities". ReliabilityFirst recommends modifying either R3 or R4 to use consistent language. 6. Data retention – ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example the last sentence states "the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data

Retention section.
No
For the TOP-001-2 standard, ReliabilityFirst disagrees with the VSLs for the following reasons: 1. VSLs for R3, R5 and R6 – ReliabilityFirst recommends adding the gradated language of “or X% or less of the entities whichever is less” to the VSLs (this is consistent with the language stated in the TOP-002-3 and TOP-003-2 VSLs). This is needed for smaller Transmission Operators which may have less than four other TOPs to inform. 2. Note in front of VSL 5 – ReliabilityFirst recommends removing the note in front of VSL5 since the note is contrary and is in conflict on how the VSL is set up.
Group
Kansas City Power & Light
Michael Gammon
No
Requirements R3 & R5 requires TOP's to notify all other "affected" TOP’s in instances of emergency or Adverse Reliability Impact. The term "affected" is a debatable condition and subject to interpretation. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Recommend the requirement be modified to alert other TOP's whenever a TOP in an emergency or Adverse Reliability Impact operating condition becomes aware of operating conditions that would result in exceeding an SOL or IROL operating limits under N-1 contingency conditions for other TOP facilities. Modifications for these two requirements will result in subsequent changes to the Measures and VSL's for requirements R3 & R5. In requirements R9 and R11 the 30-minute transition from an unknown operating state to a known state is lost for operating from an n-1 state to a n-2 state therefore leading to an immediate violation of R9 if the facility rating is exceeded. Also, the inclusion of IROL’s in R10 and R11 makes these requirements confusing as to who is responsible for mitigation, IROL’s should be removed from here as they are considered in the IRO requirements, these requirements should only address SOL’s. Requirement R8 uses the term “continuous duration”. The term “continuous duration” will be subject to interpretation as to its meaning and intent. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Also, a draft Reliability Directive definition is included in this standard but needs approval in the COM-002 standard, what if COM-002 does not get approved?
No
The words “develop a plan” in R2 are too broad. Recommend the requirement be modified to include, “within its TOP area” as in R1. Also the use of “Contingency event conditions” is not clear in requirement R1. Recommend specifying n-1 as the contingency scope.
No
These requirements do not recognize the limitations of data exchange capability with an entity and the sources of data an entity has. Recommend these requirements be modified to include "within the data exchange capabilities and data available of the recipient of the data specification".
No
The VSL for TOP-003-2, R5 does not recognize partially satisfying a request for data. Recommend the SDT consider a graduated set of severity levels similar to the other requirements in TOP-003-2.
No other comments.
Individual
Don Schmit
Nebraska Public Power District
No
Instead of using ‘its’ TOP in R1 we suggest using ‘a’ TOP since it is possible for the listed entities to have multiple TOPs. In R3, suggest rewording as “Each Transmission Operator shall inform its Reliability Coordinator, and other Transmission Operators, of each actual and anticipated Emergency that they are known or expected to be affected by, based on its assessment of its Operational Planning Analysis”. The existing language doesn’t clearly specify what is to be communicated with affected entities. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9, even in situations where the inititating event was outside of design criteria. Current language allows exceedance of an IROL for a specific time, but does not appear to give any time to readjust the system for the less severe SOLs. This does not seem reasonable. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn’t identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by ‘internal area reliability’? How does it differ from reliability of a TOP Area as included in R5? Suggest “Each Transmission Operator shall inform its Reliability Coordinator of each SOL identified by the Transmission Operator as supporting the reliability of its Transmission Operator Area”. With the inclusion of internal area reliability in R8 and R9, aren’t these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who’s responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using ‘its’ RC in R6 rather than ‘the’ RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
No
Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. We suggest the following language for R1: “Each Transmission Operator shall have an Operational Planning Analysis assessing whether the planned Transmission Operator Area operations for the next day will exceed the area Facility Ratings or Stability Limits during anticipated normal and Contingency (at a minimum N-1 Contingency planning) event conditions.” Requiring the TOP to develop a plan to operate within each IROL in R2 is too broad. To narrow the scope of this requirement we suggest inserting the phrase ‘within its Transmission Operator Area or for which it has been notified by another TOP

under R3' in R1 immediately following (IROL).
No
Comments: Requirements R1 & R2 do not put any meaningful bounds on the data that a TOP or BA may request in the name of monitoring real-time operations. There is no check or balance on spcifying timeframes when the data is required either. Attachment 1 TOP-005-1 contained the type of data that may be required and as such provided a fremework for what type of data was required for real-time monitoring of the Bulk Electric System. As written, it would be possible for a BA or TOP to request data that a registered entity does not have available and require it in an unrealistic timeframe. This puts those entities in a position where they cannot comply with the standard, even though the data requested may not be important in the monitoring of the Bulk Electric System. There need to be reasonable limits on the information requested and how quickly new information may be required from other registered entities.
No
TOP-001-2, R3 Moderate VSL – the word “affected’ has been omitted and needs to be inserted. TOP-003-2, R1 & R2 – The use of the term ‘element’ in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 – The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn’t this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
The definition of Reliability Directive is contained in COM-002-3 and that standard hasn’t been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Individual
Bob Thomas
Illinois Municipal Electric Agency
No
Illinois Municipal Electric Agnecy supports comments submitted by the SERC OC Standards Review Group and the ISO/RTO Standards Review Committee concerning the need to address the “Reliability Directive” definition in concert with COM-002-3.
No
Illinois Municipal Electric Agency supports comments submitted by Indiana Municipal Power Agency concerning the need for clearer communication of data specifications in R3 and R4 in order to facilitate compliance with R5.
No
Illinois Municipal Electric Agency supports comments submitted by the ISO/RTO Standards Review Committee concerning the need to build some flexibility into the VSL for TOP-003-2 R5.
Illinois Municipal Electric Agency appreciates SDT efforts to develop a sixth draft for this proposed Reliability Standards development. While we realize the SDT will never be able to resolve all concerns, it appears from our own review and our review of other entity comments that additional revisions are needed to achieve a level of quality that will minimize difficulties complying with these Reliability Standards.
Individual
Greg Rowland
Duke Energy
No
While the drafting team has made several improvements to this standard, we believe these additional changes are needed: • The definition of Reliability Directive includes the defined term “Adverse Reliability Impact”, which should be replaced by the actual wording of latest BOT-approved definition of “Adverse Reliability Impact”, since it has not yet been approved by FERC. If the SDT decides not to replace Adverse Reliability Impacts with the actual wording of the latest BOT-approved definition, then the SDT should delete the “s” from “Impacts”. • R8 – We believe that the phrase “supporting its internal area reliability” should be further clarified in some way. The inclusion of the undefined concept of “supporting internal area reliability” creates undue compliance risk, since auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”. The drafting team could examine the disturbance reporting criteria in EOP-004-1 Attachment 1 to help develop a reasonable threshold for reporting SOLs to the Reliability Coordinator. • R8 – Consistent with R3, the Time horizon for R8 should only be Operations Planning. • R9 – The change that has been made to R9 could be interpreted to result in a violation if a facility rating is exceeded for any amount of time at all. Similar to an IROL’s Tv, SOLs identified under R8 should have an identified time period (such as 30 minutes) for mitigation without a violation. A change to R9 should be coupled with development of a reporting threshold for R8 as discussed above. • M1 – typo, left the “u” off the word “unless”. • Measures for R8 and R9 should be changed consistent with our suggested revisions to the requirements.
No
• R2 – Consistent with our comment above on TOP-001-2 Requirement R8, the phrase “supporting its internal area reliability” should be further clarified in some way. • M2 typo – the word “plan” has an extra “n”.
Yes
• R1.1 – Consistent with our Question #1 comment above on using the actual wording of the BOT-approved definition of “Adverse Reliability Impact” since it has not yet been approved by FERC, “Operational Planning Analysis” has likewise not yet been approved by FERC as of the latest version of the Glossary posted on the NERC website, December 13th, 2011. Suggest using the wording of the defined term. If the SDT decides to instead keep the defined term, “Analyses” should be “Analysis”. • R3 – Current wording is awkward. Suggest rewording as follows: “Each Transmission Operator shall distribute its data specification to entities that have data required for operating analysis assessment processes and reliability monitoring tools used by the Transmission Operator in meeting its NERC-mandated reliability requirements.” • R4 – Current wording is awkward. Suggest rewording as follows: “Each Balancing Authority shall distribute its data specification to entities that have data required for reliability monitoring tools used by the Balancing Authority in meeting its NERC-mandated reliability requirements.” • Measures and Data Retention – change to align with suggested R3 and R4 rewording above.

No
• TOP-001-2, R8 – Consistent with R3, the Time horizon for R8 should only be Operations Planning. • TOP-001-2 VSLs for R8 and R9 should be changed consistent with our suggested revisions to the requirements. Also see comment below regarding use of percentage ranges. • TOP-002-3 VSLs for R3 – the addition of the percentage range on the Lower VSL makes no sense. The “whichever is less” phrase on the other VSLs could push a violation into a higher VSL because of the percentage range. For example, if the TOP had 10 entities to notify and failed to notify one, then it would be a Moderate violation (10%) instead of Lower. If the TOP had 100 entities to notify and failed to notify four (less than 5%), then it would still be a Severe violation. • TOP-003-2 VSLs for R1 - “Analyses” should be “Analysis”, since “Operational Planning Analysis” is a defined term. • TOP-003-2 VSLs for R2 – Severe VSL should just say “four” instead of “four or more” because there are only four required elements. • TOP-003-2 VSLs for R3 and R4 – the addition of the percentage range on the Lower VSL makes no sense. See comment on TOP-002-3 VSLs for R3 above.
Individual
Edvina Uzunovic
The Valley Group, a Nexans Company
TOP-004-2 R4: If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits, as determined by System Operating Limits or real-time measurements, have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits (SOLs or Real-Time Limits) within 30 minutes. TOP-006-2 R1.2 Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources, as determined with SOLs or Real-Time Calculated limits, available for use. TOP-006-2 R2: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real time operating capacity, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. TOP-008-1 R2: Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall operate the Bulk Electric System to the actual real-time limits (if available) or the most limiting derived parameter. TOP-008-1 R3: The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. The Transmission Operator shall review the real time status and capacity of transmission facility prior to disconnecting, if applicable. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter. TOP-008-1 R4: The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation. If applicable, and prior to immediate mitigation, the Transmission Operator shall review real time status and capacity of the equipment, and based on those, made necessary adjustments.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
Please provide clarity on the phrase "support its internal area reliability" in R8.
No
Please provide clarity on the phrase "support its internal area reliability" in R2.
Yes
No
There is a mistake in the mapping document for TOP-001-2 R11 as the language doesn't match the language in the Standard. There is additional language in the mapping document that states "within 30 minutes," which the standard does not, and should not say. This occurs on page 36 for the mapping of current TOP-007 R2 to proposed TOP-001-2 R11. Additonally, SCE&G believes that it would be erroneous to remove TOP-004 R5 on the basis of the functional model. The functional model for the TOP stipulates that the TOP "is responsible for the real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably." If a situation were to arise where there was not sufficient time to contact the RC or if the RC was taking action that would put the TOP in jeopardy, SCE&G believes that the TOP has the right to separate from the Interconnection to protect the reliability of its system as is spelled out in current standard TOP-005 R5.
Group
SERC OC Standards Review Group
Gerald Beckerele
No
We suggest that the definition of Reliability Directive should be modified as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or “an event that results in Bulk Electric System instability or Cascading”. We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition. We suggest the Standard Drafting Team further clarify or define the term “supporting internal area reliability” as an aid in demonstrating compliance and how this requirement enhances reliability. We

suggest including “Real-time Assessments” in this standard to clarify Operations Planning and same day operations time horizons (Requirement 8). We request that the drafting team review and explain the differences in the time horizons for Requirements 3, 5 and 8.
No
Why did the Drafting Team use the terms “Facility Ratings” and “Stability Limits” in Requirement 1 rather than SOLs and IROLs as used in subsequent Requirements? We suggest the Drafting Team further clarify or define the term “supporting internal area reliability” as an aid in demonstrating compliance and how this requirement (R2) enhances reliability.
No
There appears to be ambiguity for R1 and R2 - is the VSL applicable to the TOP/BA requesting the data or is it applicable to the TOP/BA providing the data? If it applies to the TOP/BA requesting the data we would suggest that the SDT be consistent with the VSLs in IRO-10-1a.
See responses to questions above.
Data retention requirements for TOP-001-2. TOP-002-3 and TOP-0003-2 need to align with the expectations of the compliance entity. “The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.”
Group
Georgia System Operations
Neil Phinney
Yes
GSOC agrees in general but feels that some clarity should be provided. The purpose of the language "each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis" (OPA) is not clear. Is the intent to clarify the meaning of SOL? If so the definition in the glossary should be updated to clarify the meaning and the clarification should be removed whenever used in TOP-001, 002, or 003. Is the intent to limit which SOLs are being referred to? Not each SOL but each SOL which have been identified as supporting the internal area reliability based on the assessment of its OPA. Could this language be deleted and still convey what is required?
No
GSOC feels that some clarity should be provided. In R1, the rationale confuses things. It states things that are not in the requirement and goes beyond the requirement. If something is intended by the language of R1 other what is stated, then that intent should be clearer in the requirement. For example if a process is required, then state so in the requiremnt. It should not be in a rationale. Also, the comment in the rationale about being able to complete the analysis even if tools are not available is inappropriate in this standard since the situation is covered in EOP-008-1. Remove the rationale and if needed clarify the requirement. R1 states that the TOP should be allowed to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. It does not state that an assessment of this must be done, only that it be allowed. R2 states that the TOP shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which has been identified by the TOP as supporting its internal area reliability, identified as a result of the OPA performed in Requirement R1. R1 does not require that IROLs and SOLs be identified. What if the TOP does not identify if there are any SOLs as a result of the OPA? There are other examples in these standards in which something in the OPA is referred to but is not required to be in the analysis. Better clarity is needed regarding just what the end results of the analysis must be. R3 requires that entities identified in the plan be notified as to their role. Would this be initially and whenever their role changes thereafter? Or just once? Data Retention: It states that if a TOP is found non-compliant, it shall keep information related to the non-compliance until found compliant. It is inappropriate to use the phrase "found compliant." NERC and the REs do not find entities compliant.
No
R5 is too unilateral. A TOP could send a spec to an entity for some data that the entity is not able to provide and per this requirement the entity will still be required to provide it. There must be some mutual agreement to more than just the format. There must be agreement to what can be provided and that the data is needed by the TOP’s operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements. Also some provision must be allowed to cover when data or the transfer method is unavailable (e.g., when an RTU goes down). A similar situation applies to BAs sending a spec to an entity.
GSOC believes that all 3 standards should be voted on together in one vote. They are too inter-related. One or two of these should not be approved if one of them is not approved.
Individual
Terri Pyle
Oklahoma Gas and Electric
No
A. In the draft TOP-001-2 standard, R1 and R2 both address complying with Reliability Directives. OG+E suggests these two requirements be combined into one requirement using similar language found in other standards that contain the same Reliablity Directive requirement, such as IRO-001-1.1 R8 and the previous version of this standard for consistency purposes. B. Mitigation of IROLs is ultimately the responsibility of the RC. TOPs act under the direction of the RC when mitigating IROLs. TOP-001-2 R11 should clarify by adding the following to the beginning of the requirement. "Under the direction of the RC, each TOP shall act or direct others to act...". C. Please clarify the meaning of "internal area realiability" in R8. D. In R9, "continuous duration" warrants additional clarification. Is this 5, 10, 30, 60 minutes of operating outside the SOL? Or only continuous operation outside of SOL that results in ultimately exceeding the Facility Rating?
No
Regarding R2, please consider additional clarifying language that each TOP need only develop a plan to operate within

IROL and SOL that is applicable to them. Also, clarify what "internal area realibility" means - is this the same as Transmission Operator Area discussed in R1?
Yes
Individual
Julie Lux
Westar Energy
Yes
No
The stated rationale for R1 raises more concerns than the actual language in R1. How can an entity complete an analysis by procedure? The rationale seems to indicate that an Operational Planning Analysis is possible without tools, please explain. Are anticipated contingency event conditions intended to be N-1 from the planned system configuration?
Yes
No additional comments.
Group
MRO-NSRF
Will Smith
No
Issue: Upon review of the NERC Glossary of Terms, please drop the “s” from “…or Adverse Reliability Impacts” within the definition of a Reliability Directive. Issue: M1; It is not necessary to repeat the Requirement within the Measure. Recommend “unless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1”, be removed from this Measure. Issue: M4; It is not necessary to repeat the Requirement within the Measure. Recommend “unless such actions would violate safety, equipment, regulatory, or statutory requirements”, be removed from the Measure. Issue: Upon review, it is noted that ‘Coordination of’ has been struck from Purpose, however not removed from the Title of the Standard. Recommend changing ‘interconnection’ in the Purpose to ‘Bulk Electric System (BES)’ Issue: R3: The statement “…Transmission Operators that are known or expected to be affected…” the use of “known or expected” is redundant. Recommend removing ‘known or expected’ and have the requirement rewritten as follows: Issue: R3: Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. Issue: R8: The statement “…its internal area reliability…” should be clarified to state: R8: Each Transmission Operator shall inform its Reliability Coordinator of each of its SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its Transmission Operators area based on its assessment of its Operational Planning Analysis. Issue: M8: statement “…its internal area reliability…” should be clarified to state: “…has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis…” Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you can’t draw SOLs into the same category as IROLs unless you clearly indicate these standards only apply to a subset.
No
Issue: The SDT uses a non FERC approved term of “Operational Planning Analysis”, This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval. Issue: R2: statement “…its internal area reliability…” Should be clarified to state: R2: Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: statement “…its internal area reliability…” could be clarified to state: “…has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis…”
No
Issue: There is a great possibility of “double jeopardy” when R3 and R4 have in part the statement of “…in meeting its NERC-mandatory reliability requirements.” So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown “…in meeting its NERC-mandatory reliability requirements” then they would be found non compliant with this Standard. It is not clear why this Standard is being written with the statement of: “…in meeting its NERC-mandatory reliability requirements”. As stated in the NERC Standard Process Manual, under Background, “NERC works with all stakeholder segments of the electric industry, including electricity users, to develop standards for the reliability planning and reliable operation of the bulk power systems. Recommend that “…in meeting its NERC-mandatory reliability requirements”, be deleted and replaced with “reliable operation” as defined as “…operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance…”. Or, please review IRO-010-1a, requirement 1 and use like terminology for this Standard.
None
None
Group
Western Area Power Administration
Brandy A. Dunn
Yes

Yes
No
Data an entity specifies in requirement documents need to have some kind of reasonability limit or explanation as to what the data will be used for. As written a TOP or BA can request anything they want and other entities will be required to provide that data, even if the requested data is not available as requested. An entity can also request data not pertinent to the reliability of their system and other entities will still be required to provide it. An entity required to provide the data should have an opportunity to challenge the need for data requested. At least one BA in WECC is running a market and data provided will be used in their market, not for reliability.
TOP 1 and 2 as written are generally acceptable. TOP 3 opens doors for manipulation.
Individual
Thad Ness
American Electric Power
No
R7, R9, R10, & R11 – It needs to be clarified whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader. Taken together, the combination of R7 and R9 appears redundant with R11, as meeting the objective of R7 and R9 would imply taking the proper mitigating measures. AEP suggests either eliminating both R7 and R9 or eliminating only R11. If r7 and R9 were to be eliminated, the references to magnitude and duration should be removed from R11, as the associated measure is binary in respect to the limit, i.e., either the limit has been exceeded or it has not. It would be premature for AEP to support the associated VSLs and VRFs given the objections stated above.
Yes
R2: Once again, it needs to be clarified whether this requirement is in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader.
Yes
R5: It should be noted that some of the information that could potentially be requested may already be available, for example on reliability coordinator systems. AEP suggests that the requirement be modified so that it does not unintentionally create an edict to provide “any data” to parties simply because R5 could be interpreted as allowing requests of any kind. The possibility of a dispute resolution process managed by the reliability coordinator(s) might also address these possible scenarios. Such a process should address, at a minimum, specifics such as timing, format and general logistics concerning the requested data. AEP does not currently have any text to suggest in this regard, but asks the SDT to consider such a change.
No
In general, the VRFs and VSLs are too severe and punitive. Because of this, as well as our objections with the redundancy of requirements in TOP-001-2, AEP cannot support the proposed VRFs and VSLs.
Individual
Brenda Truhe
PPL Electric Utilities
No
We believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
Individual
Bill Keagle
BGE
No
BGE concurs with ISO/RTO Standards Review Committee Position: Instead of using ‘its’ TOP in R1 we suggest using ‘a’ TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn’t identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by ‘internal area reliability’? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren’t these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who’s responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using ‘its’ RC in R6 rather than ‘the’ RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.

No
BGE concurs with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
No comment.
No comment.
We realize that SDT for Project 2006-06 is responsible for defining Reliability Directive; however, we would like to reiterate our position that the definition must capture the identification concept that is reflected in Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. Additionally, the currently proposed definition of Reliability Directive is also contained in COM-002-3 and IRO-001-3 which have not been approved at this time. What happens if the TOP standards are approved and the COM and IRO standards are subsequently not approved or change? The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. Since the two projects appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently. We are voting affirmatively because we support the improvements achieved by the drafting team work so far. However, we raised remaining concerns with the standard proposal on the comment form submitted on behalf of BGE. We expect the drafting team to continue to make clarifying changes until the end of this stakeholder process. The greater the clarity in the final product, the less risk of contradictory perspectives on compliance.
Group
Constellation Energy
Brenda Powell
No
The definition of Reliability Directive is an improvement but the definition must capture the identification concept that is reflected in the Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. We suggest the following revision to the definition and it should follow through to Project 2006-06 (COM-002-3 and IRO-001-3), eventually being added to the Reliability Standards Glossary of Terms. A communication identified as a Reliability Directive by a Reliability Coordinator, Transmission Operator, or Balancing Authority to initiate action by the recipient to address an Emergency or Adverse Reliability Impact. The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. CCG, CECD and CPG agree with ISO/RTO Standards Review Committee Position: Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs – the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well
No
CCG, CECD and CPG concur with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
No
The Drafting Team may want to consider addressing a time period for responding to a data request to ensure parties are given time to respond. For example, a BAs data request may be driven by the TOP's data request. If a BA receives a data request for information from the TOP that sources from a GOP, the BA will need to establish a data request from the GOP that has the same deadline. If the GOP is unable to supply the data they may be non-compliant if they do not meet the deadline.
The definition of Reliability Directive is contained in COM-002-3 which has not been approved at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved or change? Since the two projects appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently.
Individual
Kirit S. Shah
Ameren
No
R2. When is "shall inform" to occur; timely, promptly, … It would be injurious to BES reliability for the TOP to get such information, say 15 minutes or half-hour later as many other things are likely to be put in place on the assumption the directive is "ok". R3. The wording is incorrect it implies the TOP will notify the RC and its TOP's. The word other may be

missing. But even with other the question it begs which other TOP's? It could be argued that the RC only needs to know Emergencies that are both actual and anticipated. They would want to know about them whether they are actual or anticipated. This direction here is not clear; it may be helpful to use two sentences to address and clarify the issues of this requirement. R4. What is meant by emergency assistance is not clear; clarify and provide examples. Is it emergency energy? Is it emergency food? Is it emergency crews? This ambiguity is a compliance nightmare as you have to prove you have everything covered that could loosely be interpreted as emergency assistance. If the SDT has an idea what they are expecting, it should be listed. If they don't have an idea of what constitutes emergency assistance, then we recommend removing it from the Requirement. R5. The Requirement should be re-written to say "Each TOP shall inform only if it adversely affects others its RC and other TOP's (Which other TOP's? This direction here is not clear; clarify) of its operations known or expected to result in an Adverse Reliability Impact …" R6. What is meant by negatively impacting is not clear; clarify and provide examples. For example, using the words as listed, economic impact might be a consideration. The Standard should not be setting up a condition where TOPs tell GO/GOPs that they might suffer economic harm as a result of one of the communication channels being down. As currently worded this might lead to a civil issue instead of a BES reliability issue. R8. There are SOLs that are developed in real-time (as evidenced by the multi-time-horizon assigned). It might be possible for such an SOL to develop and have to be resolved for local area reliability only, before the RC could be notified. This Requirement should insert the word planned before SOL. Alternatively, insert where time permits in place of real-time. R9. What is meant by continuous duration is not clear; clarify. Is it 5 minutes, 15 minutes, an hour, a day? Anything more than 5 minutes is likely to be in the thermal time-constant period where rating could be affected. We feel that the real intent of this requirement is that TOPs resolve SOLs. It is not so much how long, as it is that they are not purposely delaying the resolution. The Requirement should be re-written to say "The TOP's will resolve as soon as possible anys SOL…… with no intentional time delay…" R10. The Requirement as written should be prefaced with "when time permits, each Transmission Operator….." The idea of time permitting is alluded to in R5, "unless conditions do not permit such communications".
No
R1. The current language invites a retrospective assessment and a potential compliance issue that if a bad event occurs that was not in the forecast, it may call into question whether the TOP adequately "allowed it to assess" whether operations where within limits. We recommend SDT re-write the requirement: "Each TOP shall have an Operational Planning Analysis that represents projected System conditions for the next day, within its Transmission Operator Area, to identify any projected exceedance of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions." R2. Although the time-horizon assignment provides some cover for real-time SOLs, it would be preferable to add direct clarification to the Requirement as follows. "Each TOP shall develop a next day plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) …" R3. Taken literally, this Requirement could require TOP notification to a GOP/PSE/LSE that they will be dispatched down in real-time for a projected congestion issue (SOL). This does not make sense and certainly not in organized LMP markets where they would have advance knowledge of market conditions AND FOR THINGS THAT ARE ROUTINE. This is the nexus of the problem for us with this Requirement. The need to notify others of their roles should be restricted to unusual actions in the case of SOL resolution. Arguably this could be true for IROLs too but given the impact perhaps it could remain. We suggest that the Requirement say, "Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) when those actions are unusual or abnormal actions." OR "Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) for the resolution of IROLs or when those actions are unusual or abnormal actions for the resolution of SOLs."
No
R1. Each TOP shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: 1.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the TOP. This is illogical and needs to be clarified or removed. 1.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R2. Each BA shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. The specification shall include: 2.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the BA. This is illogical and needs to be clarified or removed. 2.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R3. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert "from R1" There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they should be spelled out explicitly here and likely in R1 as well. R4. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert "from R1" There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they should be spelled out explicitly here and likely in R1 as well. R5. We recommend re-writing: "Each TOP, BA, GO, GOP, IA, LSE, and TO receiving a data specification in Requirement R3 or R4 shall provide the data associated with said data specification. "
No
See comments in question 5 regarding VRF.
We highly recommend that you do not lump requirements that include SOL with IROL. IROLs by definition should have VRFs higher than SOL. So it is not possible to properly assign the VRF consistent with the NERC VRF/VSL Guideline documents. We would suggest that the SDT could review what the FAC-003 SDT has done and then provide separate Requirements when there are known and expected VRF differences for different elements covered by a combined Requirement.
Group
ACES Power Marketing Member Standards Collaborators
Jason Marshall
No
We largely agree with the changes but have identified the following specific issues. We disagree with removing Bulk

Electric System (BES) from the purpose of the standard. NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Substituting BES for "interconnection" in the purpose statement may solve this issue. While the title contained in the header was changed to "Transmission Operations" the actual title was not changed. They should match. For simplicity, we recommend striking "known or expected to be" from Requirement R3. As it is written now, it is more confusing. First, the TOP, can only notify other TOPs that it knows are affected. Second, the use of "expected" implies that something different is meant than known. If so, what is the intention of the meaning and whose expectation is it: the responsible TOP, the other TOP, the auditor or some other entity? There is a similar issue regarding "known or expected to result in an Adverse Reliability Impact" in Requirement R5. We recommend striking "or expected" for simplicity and to avoid the confusion of whose expectation it is. In Requirement R8, "while not IROLs" should be "while not an IROL". We agree with removing the 30 minute limit in Requirements R9 and R11 and basing the time limit upon the Facility Rating or Stability criteria. In Requirement R10, striking "each" before SOL would improve the clarity of the requirement. In Measurement M1, "nless" should be unless. This may already be correct. The red-lines show "nless" and the clean document shows "unless". What is the intended difference between Transmission Operator Area in Requirement R5 and internal area in Requirement R8? Should they be the same and if not why not?
No
We largely agree with the changes but have identified the following specific issues. We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted into the purpose statement. For Requirement R1, it is not clear why focus is on Facility Ratings and Stability Limits rather than SOLs. We suggest using the term SOL instead.
No
We largely agree with the changes but have identified the following specific issues. We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Because of the difficulties experienced by some entities in receiving the RC data specification in IRO-010-1a, we recommend that the implementation of TOP-003-2 Requirement R5 occur a couple of months after the implementation in TOP-003-2 Requirements R1-R4. IRO-010-1a is a parallel standard to TOP-003-2 and the effective date of the distribution of the RC data specification was simultaneous to the effective date of the requirement for the recipients to comply with the data specification. This meant that the RC could provide the data specification on the same date that the recipients had to meet the data specification. Unfortunately, there were some entities expecting to receive the data specification that did not and were concerned about a potential non-compliance. What if an auditor determined the RC should have provided the data specification? Would the entity that expected to receive the data specification be held responsible? By staggering the effective date of Requirement R5, this confusion can be avoided.
No
The VSLS for TOP-002-3 Requirements R1 and R2 could have more levels based on the number of days for which there is not a plan or Operational Planning Analysis.
Group
City Water Light and Power (CWLP) - Springfeild - IL
Shaun Anders
No
R8 requirement to identify "…SOLs which...have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis" is vague and difficult to measure. "Internal area reliability" could conceivable include all SOLs CWLP echoes SERC Operating Committee comments submitted separately: "We suggest that the definition of Reliability Directive should be modified as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or "an event that results in Bulk Electric System instability or Cascading". We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition."
No
R1 should utilize SOL and IROL criteria as opposed to Facility Ratings and Stability Limits criteria for consistency and clarity R1 Rationale language lacks clarity. Poor definition of "process", "tools", and "procedures" could be construed to indicate that a TO must be able to perform analysis internally even when basic non-automated "tools" such as offline power flow software are not available. The intent of "tool" is unclear in general for this instance. If the intent is to capture the use of online automated tools such a Real-Time Contingency Analysis and ensure that offline analysis capabilities are retained, the language should explicitly include "online automated tools" or "real-time automated tools"
No
R1 and R2 require specifications for data exchange which do not account for the ability of the respondent to meet the specification. As written, the requirement could force a respondent to continue to provide data with such a format, periodicity, or deadline that would be an undue burden to the respondent. All requirements should explicitly stress a mutually agreed plan and R1.1/R2.1 should refer to classes or types of as a qualifier. Likewise, R5 should explicitly state that respondents shall satisfy the obligations within the context of a mutually agreed specification.

Individual
Jason Snodgrass
GTC
No
M4 is misreferencing R2 and R4 and should be corrected as follows: ….”receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R5.”
Demonstrating providing all data specifications for real time operations horizon is very prescriptive in nature and could have unanticipated "compliance documentation" consequences when data or the transfer method is unavailable (e.g., when an RTU goes down).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Real-time Transmission Operations Project 2007-03

The Real-time Transmission Operations Drafting Team thanks all commenters who submitted comments on the 6th draft of the standards for Real-Time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from December 14, 2011 through January 12, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 59 sets of comments, including comments from approximately 178 different people from approximately 103 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The SDT changed the following items due to industry comments received:

- TOP-001-2:
    - Requirement R1 – Allowed for plural Transmission Operators and deleted first instance of 'identified'
    - Requirement R6 – changed 'the' to 'its' Reliability Coordinator
    - Requirement R8 – changed 'internal area ' to 'internal to its Transmission Operator Area'; changed the Time Horizon to only Operations Planning
    - Requirement R10 – changed 'each' SOL to 'an' SOL
    - Data Retention – Changed voice recordings to 90 calendar days from three calendar months
- TOP-002-3:
    - Requirement R3 – changed 'internal area ' to 'internal to its Transmission Operator Area'
- TOP-003-2:
    - Applicability – added Distribution Provider
    - Requirement R2 – added analysis functions for the Balancing Authority
    - Requirement R3 – Cited the tie to Requirement R1 and made the language in Requirement R3 consistent with that in Requirement R1
    - Requirement R4 - Cited the tie to Requirement R2 and made the language in Requirement R4 consistent with that in Requirement R2
    - Requirement R5 – added Distribution Provider
    - Measures M3 and M4 – clarified the web posting item of evidence

In addition, the SDT changed VSLs for TOP-001-2, Requirements R1, R3, R5, R8, and R10, plus VSLs for TOP-002-3, Requirement R3, and TOP-003-2, Requirements R1, R2, R3, and R4.

After the Quality Review was completed, the SDT made the following changes:

- TOP-001-2:
  - Requirement R1 – eliminated the plural context
  - Requirement R3 – clarified the plurality context
  - Requirement R5 – clarified the list of items
  - Measures – added attestations as evidence when no event has occurred
  - Compliance section – updated to latest revision
  - VRF justifications – moved away from using proposed requirements where possible
  - Requirement R1 VSL – clarified language
  - Requirements R3, R5, and R6 VSLs – added percentages
  - Requirement R8 – added language to exactly match requirement
  - Issues resolution – clarified language
  - Implementation Plan – clarified language
- TOP-003-2:
  - Requirements R1 and R2 – deleted use of 'required'
  - Measures M3 and M4 – corrected typo
  - Compliance section – updated to latest revision
  - VRF justification - moved away from using proposed requirements where possible

Minority comments included:

- Use of Reliability Directive – Some commenters object to the use of an unapproved definition, Reliability Directive, in TOP-001-2. They feel that it presents coordination problems and could cause a change to the standard if the definition is changed during its balloting. The SDT explained that it was working closely with Project 2006-06 which is developing the definition. Indeed, there are several members of the RTOSDT who are also on the RCSDT. The SDT also assures commenters that the need to coordinate filing the two projects, 2006-06 and 2007-03, has been forwarded to NERC management.
- There was concern about possible double jeopardy with TOP-003-2, Requirements R1/R3 and R2/R4. The SDT explained that double jeopardy should not be a concern as the two requirements represent two different actions: one to create the specification and one to distribute it. The two separate and distinct actions mean that there are two distinct reliability outcomes and that two separate requirements are needed.

TOP-001-2 did not pass initial ballot. The SDT made several changes to this standard to respond to comments and negative ballots. The SDT is recommending that TOP-001-2 be approved for a successive ballot.

TOP-002-3 passed its initial ballot but the SDT made a change to the effective date in response to comments. Therefore, the SDT is recommending that TOP-002-3 be advanced to a successive ballot.

TOP-003-2 did not pass initial ballot. The SDT made several changes to this standard to respond to comments and negative ballots. The SDT is recommending that TOP-003-2 be approved for a successive ballot.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC	8
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Chantel Haswell	FPL Group, Inc.	NPCC	5
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

11.	Michael R. Lombardi	Northeast Utilities	NPCC	1
12.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

2.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Robert Rhodes	Southwest Power Pool	SPP	2
3.	Ashley Stringer	OMPA		4
4.	John Allen	City utilities of Springfield	SPP	1, 4
5.	Michelle Corley	CLECO	SPP	1, 3, 5
6.	Ron Gunderson	NPPD	MRO	1, 3, 5
7.	Terri Pyle	OGE	SPP	1, 3, 5
8.	Valerie Pinamonti	AEP	SPP	1, 3, 5
9.	Tiffani Lake	Westar	SPP	1, 3, 5, 6
10.	Jim Useldinger	KCPL	SPP	1, 3, 5, 6
11.	Mahmood Safi	OPPD	MRO	1, 3, 5

3.	Group	Joe O'Brien	NIPSCO	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe O'Brien	NIPSCO	RFC	1, 3, 5, 6

4.	Group	Annie Lauterbach	Bonneville Power Administration	X		X		X	X				

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Loepker	Dittmer Dispatch	WECC	1
2.	John Anasis	Technical Operations	WECC	1
3.	Theodore Snodgrass	Monroe Dispatch	WECC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Albert DiCaprio	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mark Thompson	AESO	WECC	2
2.	Gary DeShazo	CAISO	WECC	2
3.	Steven Myers	ERCOT	ERCOT	2
4.	Ben Li	IESO	NPCC	2
5.	Matt Goldberg	ISO-NE	NPCC	2
6.	Bill Phillips	MISO	RFC	2
7.	Donald Weaver	NBSO	NPCC	2
8.	Greg Campoli	NYISO	NPCC	2
9.	Patrick Brown	PJM	RFC	2
10.	Charles Yeung	SPP	SPP	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Reed	FE	RFC	
2.	Kevin Querry	FE	RFC	
3.	Bill Duge	FE	RFC	
4.	Brian Orians	FE	RFC	
5.	Gary Pleiss	FE	RFC	
6.	Sherri Rhodes	FE	RFC	

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Juel Fugett	IID	WECC	1, 3, 4, 5, 6
2.	Alfonso Juarez	IID	WECC	1, 3, 4, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Jonathan Hayes	Southwest Power Pool Reliability Standards Development Team		X								

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

1.	Jonathan Hayes	Southwest Power Pool	SPP	2
2.	Robert Rhodes	Southwest Power Pool	SPP	2
3.	Ashley Stringer	OMPA		4
4.	John Allen	City utilities of Springfield	SPP	1, 4
5.	Michelle Corley	CLECO	SPP	1, 3, 5
6.	Ron Gunderson	NPPD	MRO	1, 3, 5
7.	Terri Pyle	OGE	SPP	1, 3, 5
8.	Valerie Pinamonti	AEP	SPP	1, 3, 5
9.	Tiffani Lake	Westar	SPP	1, 3, 5, 6
10.	Jim Useldinger	KCPL	SPP	1, 3, 5, 6
11.	Mahmood Safi	OPPD	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Garton		NPCC	5
2.	Michael Gildea		MRO	5
3.	Louis Slade		RFC	5, 6
4.	Michael Crowley		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Harold Wyble	Kansas City Power & Light	SPP	1, 3, 5, 6
2.	Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6
3.	Jessi Tucker	Kansas City Power & Light	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Gerald Beckerele	SERC OC Standards Review Group	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Vicky Budreau	Santee Cooper	SERC	1, 3, 5, 9
2.	Cindy Martin	Southern	SERC	1, 3, 5
3.	Bob Dalrymple	TVA	SERC	1, 3, 5, 9
4.	Merritt Castello	Southern	SERC	1, 3, 5
5.	Scott Brame	NCEMC	SERC	3, 4
6.	Tim Lyons	OMU	SERC	1, 3, 5
7.	Jake Miller	Dynegy	SERC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Marc Butts	Southern	SERC	1, 3, 5
9.	Mike Hirst	Cogentrix	SERC	5, 6
10.	Joel Wise	TVA	SERC	1, 3, 5, 9
11.	Andy Burch	EEI	SERC	1, 5
12.	Byron Thomasson	PowerSouth	SERC	1, 3, 5, 9
13.	Tim Hattaway	PowerSouth	SERC	1, 3, 5, 9
14.	Travis Sykes	TVA	SERC	1, 3, 5, 9
15.	Randy Hubbert	Southern	SERC	1, 3, 5
16.	Dwayne Roberts	OMU	SERC	1, 3, 5
17.	Hugh Francis	Southern	SERC	1, 3, 5, 9
18.	Larry Akens	TVA	SERC	1, 3, 5, 9
19.	Mike Hardy	Southern	SERC	1, 3, 5
20.	Greg Rowland	Duke	SERC	1, 3, 6
21.	Sam Holeman	Duke	SERC	1, 3, 6
22.	Melinda Montgomery	Entergy	SERC	1, 3
23.	Brad Young	LGE/KU	SERC	1, 3, 6
24.	Carter Edge	SERC	SERC	10
25.	Steve McElhaney	SMEPA	SERC	1, 3, 5

12.	Group	Will Smith	MRO-NSRF	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Tom Webb	WPS	MRO	3, 4, 5, 6
4.	Jodi Jenson	WAPA	MRO	1, 6
5.	Ken Goldsmith	ALTW	MRO	4
6.	Alice Ireland	Xcel/NSP	MRO	1, 3, 5, 6
7.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
8.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
9.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
10.	Scott Nickels	RPU	MRO	4
11.	Terry Harbour	MEC	MRO	3, 5, 6, 1
12.	Marie Knox	MISO	MRO	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

13.	Lee Kittelson	OTP	MRO	1, 3, 4, 5
14.	Scott Bos	MPW	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Brenda Powell	Constellation Energy						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	C. J. Ingersol	Constellation Energy Control & Dispatch	SERC	3
2.	Amir Hammad	Constellation Power Source Generation, Inc.		5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Jason Marshall	ACES Power Marketing Member Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Watson	Old Dominion Electric Cooperative	SERC	3, 4, 5, 6
2.	Mohan Sachdeva	Buckeye Power	RFC	4, 5, 6
3.	Bob Solomon	Hoosier Energy	RFC	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
16.	Individual	Eric Ruskamp	Lincoln Electric System (LES)	X		X		X	X				
17.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
18.	Individual	Brent Ingebrigtson	LG&E and KU Serivces	X		X		X	X				
19.	Individual	Neil Phinney	Georgia System Operations			X	X						
20.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
21.	Individual	Shaun Anders	City Water Light and Power (CWLP) - Springfeild - IL	X		X		X					
22.	Individual	Jonathan Appelbaum	United Illuminating Company	X									
23.	Individual	Jonathan Appelbaum	United Illuminating	X									
24.	Individual	Rich Vine	California Independent System Operator		X								
25.	Individual	Thomas E Washburn	FMPP						X				
26.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
27.	Individual	Howard Rulf	We Energies			X	X	X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
29.	Individual	Jeff Longshore	Luminant Energy Company, LLC						X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
30.	Individual	DAVID DOCKERY	Associated Electric Cooperative, Inc.	X		X		X	X				
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Robert Roddy	Dairyland Power Cooperative	X		X		X					
33.	Individual	Kathleen Goodman	ISO New England Inc.		X								
34.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
35.	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP - Occidental Chemical Corporation					X					
36.	Individual	David Thorne	Pepco Holdings Inc	X		X							
37.	Individual	Mahmood Safi	Omaha Publc Power District	X		X		X	X				
38.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
39.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
40.	Individual	Dana Showalter	E.ON Climate & Renewables					X					
41.	Individual	Don Jones	Texas Reliability Entity										X
42.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
43.	Individual	Rich Salgo	NV Energy	X		X		X	X				
44.	Individual	Gregory Campoli	New York Independent System Operator		X								
45.	Individual	Martin Bauer	US Bureau of Reclamation					X					
46.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
47.	Individual	Anthony Jablonski	ReliabilityFirst										X
48.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
49.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
50.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
51.	Individual	Edvina Uzunovic	The Valley Group, a Nexans Company										
52.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
53.	Individual	Terri Pyle	Oklahoma Gas and Electric	X		X		X					
54.	Individual	Julie Lux	Westar Energy	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
55.	Individual	Thad Ness	American Electric Power	X		X		X	X				
56.	Individual	Brenda Truhe	PPL Electric Utilities	X									
57.	Individual	Bill Keagle	BGE	X									
58.	Individual	Kirit S. Shah	Ameren	X		X		X	X				
59.	Individual	Jason Snodgrass	GTC	X									

1. **The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Comments were made on all Requirements within TOP-001-2. Most of these comments indicated individually preferred language that the SDT did not feel improved clarity, and were therefore not adopted.

In response to a large group of comments, Requirement R8 was modified to replace the phrase "its internal area reliability" with "reliability internal to its Transmission Operator Area".

The SDT clarified in its response that the term 'continuous duration' has its common meaning.

In response to comments, minor changes were made to Requirements R1, R6, and R10 to improve clarity.

The Time Horizon for Requirement R8 was changed to Operations Planning only.

Conforming changes were made to the respective Measures, VSLs, and VRFs.

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless ~~-~~such actions would violate safety, equipment, regulatory, or statutory requirements.

R6. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or ~~each~~an SOL identified in Requirement R8, has been exceeded.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
California ISO	Negative	R6 requires Balancing Authorities and Transmission Operators to notify “negatively impacted interconnected NERC registered entities” of planned outages. This term is not specific enough to narrow down who must be notified. For instance, with this open-ended wording it could be construed that BAs would have to notify LSEs and DPs in their areas which would be an onerous task. We would recommend staying with “negatively-affected BAs and TOPs.” The wording in R9 is confusing and is not specific enough to ensure compliance. In particular the requirement prohibits operation outside any SOL “for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.” However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. In addition, under R9 and M9, how will the word “continuous” be defined or measured? This is extremely important to understand because the VSL table states the following as Severe for R9: “The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria.” It seems that the effective date should be set much sooner than 24 months following approval since there are basically no new requirements associated with this standard. Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Response: Regarding Requirement R6, since telemetry has definite parties at each end, the Balancing Authority or Transmission Operator with the telemetry issue is in the best position to know which other parties are affected by its telemetry outages. No change made. Regarding Requirement R9, ratings include the element of time. In view of the current NERC definitions of IROLs and SOLs, the language is correct as is written. The definition of IROLs describes the negative results that could occur when an IROL is exceeded		

Organization	Yes or No	Question 1 Comment
for a time greater than its T_v. The definition for SOL does not have this language, so no "... instability, uncontrolled separation(s) or cascading outages...." happens upon the exceedance of an SOL that is not an IROL. No change made. In Requirement R9 and Measure M9, 'continuous duration' has its common meaning. No change made. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months for all requirements except the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Colorado Springs Utilities	Negative	Colorado Springs Utilities (CSU) appreciates the work of the SDT to reconcile the various requirements into TOP-001, -002, & -003; and this opportunity to comment. The language of this group of standards has improved much with each draft. However, CSU continues to be concerned with the creation of an apparently "special" class of SOL in TOP-001-3 R8, R9 & R11 - creating what seems to be a middle category between "run of the mill" SOLs and IROLs; with no guidance, whatsoever, on how SOLs should qualify for or be excluded from this intermediate treatment. FAC-011 & FAC-014 already adequately cover identification and communication of SOLs and IROLs, and CSU believes that, if any additional SOL categories need be created, they should be more appropriately addressed in those standards. Additionally, there is no definition and a lack clarity for the concept of "supporting internal area reliability". In previous Considerations, the SDT has stated, "Requirements R8 and R10 were added due to comments from a significant portion of the industry during the extensive posting process of these standards." But, as the SDT has acknowledged, "There is still some debate as to what is meant by internal area reliability." The SDT continued, "The SDT continues to believe, as stated in previous responses, that the Transmission Operator is best suited to determine what affects its internal area and the resolution of those issues are best left to the Transmission Operator." If best left to the Transmission Operator, then one wonders why this "special" SOL should be added to the Standard? This concept is obviously causing much consternation amongst responding entities and has

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>the makings of, at best, a moot requirement (if no-one identifies any special SOLs) or, at worst, a compliance minefield - considering the questions that will come to an auditor’s mind when trying to assess compliance with these requirements as written.

CSU also continues to feel strongly, despite protestations of the SDT to the contrary, that R7/R9 and R11 create a double jeopardy waiting to happen, and would best be appropriately combined.</td></tr>
<tr><td colspan="3">Response: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. These requirements embed that concept in the standard. No change made.

The SDT has replaced 'internal area reliability' with 'reliability within its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL<s>s</s>, <s>have</s>has been identified by the Transmission Operator as supporting <s>its internal area</s> reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

These requirements are the core Transmission Operator requirements that assure continued reliable operation of the BES. If the Transmission Operator acts or directs others to act to mitigate, as in Requirement R11, but is unable to return the facility within its IROL with a time T_v or its SOL within its time criteria, then the Transmission Operator is compliant with Requirement R11 and noncompliant with either Requirement R7 or Requirement R9, as dictated by the exact circumstances. If the Transmission Operator fails to act or fails to direct others to act, as in Requirement R11, then it is noncompliant with both Requirement R11 and either Requirement R7 or Requirement R9, as dictated by the exact circumstances. This is not double jeopardy. No change made.</td></tr>
<tr><td>MidAmerican Energy Co.</td><td>Negative</td><td>MidAmerican has concerns about TOP-001 R8 and R9. It appears the drafting team has unintentionally created an undefined subset or class of SOLs that are roughly equivalent to IROLs. More clarification is needed to clearly state that the new class of SOLs is a subset of all SOLs and not all</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		SOLs. MidAmerican recommends that R8 be modified to strike “each SOL” and replaced with “subset of Reliability Coordinator defined SOLs”. Otherwise auditors could argue that the NERC definition of a SOL includes all NERC BES devices since they all have thermal and voltage limits and therefore all NERC BES facilities apply to R8 and R9.
Response: The SDT believes that the language in Requirement R8 is clear. This requirement only applies to that subset of SOLs that are deemed to be more significant to the Transmission Operator than the typical SOL. This subset was intentionally created by the SDT in response to industry comments. The Transmission Operator must define its SOLs consistent with the Reliability Coordinator’s SOL methodology per FAC-014-2, Requirement R2. Thus, each SOL is defined per the Reliability Coordinator’s methodology. No change made.		
Muscatine Power & Water	Negative	Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the Standards Drafting Team requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9? Note that the SOL definition has a thermal rating component in it and we are not sure how you can’t draw SOLs into the same category as IROLs unless you clearly indicate these standards only apply to a subset.
Response: Typically, ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. For SOLs, the time limit varies according to the facility ratings used in the development of the SOL. No change made.		
Northeast Utilities	Negative	TOP-001-2 is referencing a NERC definition for “Reliability Directive” which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of “Reliability Directive” would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board”

Organization	Yes or No	Question 1 Comment
		usable definition.
Roger C. Zaklukiewicz	Negative	There currently is a definitionn for "Relibility Directive" which is listed in the Definition of Terms used in Standards. It is my understanding that the definition of the term "Relibility Directive" is being reviewed and probably will be rewritten/modified by the Relibility Coordinator Standards Drafting Team (Project 2006-06). Associated with this effort, is clarification of the term "Adverse Relibility Impact" which may have a significant impact on how TOP-001-2 is interpreted and administered throughout the industry. I believe the work of the Project 2006-06 Team should be coordinated with this initiative so that we have a greater level of certainty upon which we are casting a vote.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team as well.		
Oncor Electric Delivery	Negative	For R6- Oncor Electric Delivery respectfully submits this response as it does not believe that the proposed language will provide a coordinated communication effort in the event of a planned outages of telemetry, control equipment and associated communication channels. In addition, the term “negatively impacted interconnected registered entities” is too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity.
Response: The SDT is unsure of the intent of this comment, since no suggested alternative language was proposed. The SDT continues to believe that the Transmission Operator is in the best position to know which other parties are affected by its telemetry outages and it is not necessary to include the Reliability Coordinator into this item. Owner/operators of affected telemetry equipment have traditionally coordinated these outages. No change made.		

Organization	Yes or No	Question 1 Comment
Southwest Power Pool, Inc.	Negative	R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Response: The SDT made a conscious decision to raise the bar on IROLs to incorporate the T_v limit. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made.		

Organization	Yes or No	Question 1 Comment
Requirement R9 does not apply to SOLs which are not identified in Requirement R8. No change made. The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. The SDT agrees. Conforming change made. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Tampa Electric Co.	Negative	Definitions for Reliabilty Directive should be with this ballot since it is the first to be balloted Is R4 to be interpreted that I must drop Firm load if the requesting TOP is droping Firm load. The words would imply that so I can't vote in the affirmative.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team also. No change made. Shedding firm load is one of the tools for maintaining the reliability of the BES. However, this does not mean that if the initiating Transmission Operator drops load, that the cooperating Transmission Operator must necessarily drop load. It is possible, however, that two or more Transmission Operators may need to shed load to resolve an operating issue. This requirement is intended to assure that the initiating Transmission Operator cannot demand that a cooperating Transmission Operator execute emergency actions that the initiating Transmission Operator has not been willing or able to implement. No change made.		
Northeast Power Coordinating	No	Requirements R1 and R2 should not be separate. Having them broken out

Organization	Yes or No	Question 1 Comment
Council		in this manner could potentially put entities in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then Requirement R4 should be broken down into two requirements. Requirement R4 states that information is being requested, AND is available. TOP-001-2 R2 states: Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified Reliability Directive issued by that Transmission Operator. [Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations] ☐ seems problematic and further work needs to be done on this requirement to ensure that the proper intent is codified. The intent we believe to be ..immediately upon recognition of the inability to perform a Reliability Directive within the stipulated or understood timeframe would result in informing the TO. The concern exists that an entity might be able to perform the directive but may not within the proper timeframe of the TOPs need. In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning Analysis as "An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much

Organization	Yes or No	Question 1 Comment
		as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.)." What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency? The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency does not occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning.Suggest rewording Requirement R3 to:R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness

Organization	Yes or No	Question 1 Comment
		there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to “drill down” and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term “internal area reliability” in order to improve the clarity of the standard. Double jeopardy is introduced with TOP-001 R8 and FAC-014 R5.2. Fac-014 R5.2 states “The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area”; while TOP-001 R8 states “Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis.”

Response: There is no double jeopardy with separate requirements. If an entity receives a Reliability Directive and for the reasons stated in Requirement R1 can't comply with it, it is compliant with Requirement R1. If the entity fails to inform the issuer of the Reliability Directive, it is non-compliant with Requirement R2. Requirement R1 does not require the entity to inform. No change made.

As 'requested and available' is a descriptor and not separate functions. No change made.

Unless stated otherwise, a Reliability Directive should be assumed to require immediate or as soon as practicable response. The terms “immediate” and “as soon as practicable” have been debated without resolution in other projects and have been determined to be unmeasureable. The SDT sees no way to place a measurable timeframe on responding to a Reliability Directive. No change made.

The SDT sees no additional clarity from the suggested change “known or expected to be affected”. This language was chosen to cover all situations, including an ongoing event. No change made. The suggested change to remove “actual” is not adopted for the same reason: An entity could be in the midst of an on-going emergency that will continue to be present in the next-day, so the wording is correct. No change made.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">
R4: The SDT sees no additional clarity from the suggested change. No change made.

This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made.

The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.

The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. The subset of SOLs in this requirement requires special handling, thus, this requirement does not introduce double jeopardy.

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.
</td></tr>
<tr><td>Orange and Rockland Utilities, Inc.</td><td>No</td><td>
Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one’s inability to provide notice.

If each function needs to be separate, then they should break out R4 into two requirements. Who’s to say that the information is requested AND available?

In TOP-001-2 R3 the phrase “known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis” is confusing. The Glossary defines Emergency
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Organization	Yes or No	Question 1 Comment
		as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to: R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big

Organization	Yes or No	Question 1 Comment
		concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard.
Response: There is no double jeopardy with separate requirements. If an entity receives a Reliability Directive and for the reasons stated in Requirement R1 can't comply with it, it is compliant with Requirement R1. If the entity fails to inform the issuer of the Reliability Directive, it is non-compliant with Requirement R2. Requirement R1 does not require the entity to inform. No change made. As 'requested and available' is a descriptor and not separate functions. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid a noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Consolidated Edison Co. of NY, Inc.	No	Comments: Requirements R1 and R2 should not be separated. Having them broken out in this manner could allow entities to potentially be in double jeopardy when non-compliance occurs. The original language provided for a

Organization	Yes or No	Question 1 Comment
		very narrow limitation on the reasoning and the contact; and they were tied together. This language somewhat allows for the potentially different reasoning being allowed for one's inability to provide notice. If each function needs to be separate, then they should break out R4 into two requirements. Who's to say that the information is requested AND available? In TOP-001-2 R3 the phrase "known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis" is confusing. The Glossary defines Emergency as any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. The Glossary defines Operation Planning analysis as an analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). What is the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to affected by an anticipated Emergency. Those TOP's known to be affected are part of the group expected to be affected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. The Time Horizon in the Requirement is Operations Planning. Suggest rewording Requirement R3 to:R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission

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		Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Without an expressed time period for the notification in R6, doesn't this create an opportunity for broad interpretations of what is permissible and what's not? It also allows for inconsistent treatment. An auditor's view might be very different from an entity's view. Also, regarding TOP-001-2 R6, which states "Each Balancing Authority and Transmission Operator shall notify the Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities." This is a big concern. If there is coordination and notification between Reliability Coordinators, but no notification by one of the Reliability Coordinator's to the entities within the affected other Reliability Coordinator's footprint, would that be non-compliant? To ensure proper communications, notifications, and awareness there should only be one Reliability Coordinator communicating to its entities. It is impractical for Balancing Authorities and Transmission Operators to "drill down" and have to notify entities outside of their footprints of the aforementioned planned outages. Regarding TOP-001, Requirement R8: The drafting team needs to define the term "internal area reliability" in order to improve the clarity of the standard.
Response: There is no double jeopardy with separate requirements. If an entity receives a Reliability Directive and for the reasons stated in Requirement R1 can't comply with it, it is compliant with Requirement R1. If the entity fails to inform the issuer of the Reliability Directive, it is non-compliant with Requirement R2. Requirement R1 does not require the entity to inform. No change made. As 'requested and available' is a descriptor and not separate functions. No change made. The SDT sees no additional clarity from the suggested change "known or expected to be affected". This language was chosen to		

Organization	Yes or No	Question 1 Comment
cover all situations, including an ongoing event. No change made. The suggested change to remove "actual" is not adopted for the same reason: An entity could be in the midst of an on-going emergency that will continue to be present in the next-day, so the wording is correct. No change made. The SDT sees no additional clarity from the suggested change. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid a noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Southwest Power Pool Regional Entity	No	Action is only required by the proposed standards if a real time violation of a previously identified SOL occurs. No action is required in a preventative manner and no action is required as a result of a real time problem that was not identified by the Operational Planning Assessment. R5 should include notifying the RC of anticipated SOL violations. Addition in quotes. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact "or SOL violation" on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures

Organization	Yes or No	Question 1 Comment
		and changes in generation, Transmission, or Load.
Response: The 'anticipated' language addresses preventative. An assessment can happen at any time. It is not necessary to take action on an SOL. The definition of IROL describes the negative results that could occur when an IROL is exceeded for a time greater than its T_V. The definition for SOL does not have this language, so no "... instability, uncontrolled separation(s) or cascading outages...." happen upon the exceedance of an SOL that is not an IROL. No change made. The SDT does not agree. Adverse Reliability Impact captures the intent of the communications required in Requirement R5. No change made.		
US Army Corps of Engineers	Negative	Issue: Upon review of the NERC Glossary of Terms, please drop the from or Adverse Reliability Impacts within the definition of a Reliability Directive. Issue: M1; It is not necessary to repeat the Requirement within the Measure. Recommend unless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1, be removed from this Measure. Issue: M4; It is not necessary to repeat the Requirement within the Measure. Recommend unless such actions would violate safety, equipment, regulatory, or statutory requirements, be removed from the Measure. Issue: Upon review, it is noted that ˜Coordination of has been struck from Purpose, however not removed from the Title of the Standard. Recommend changing ˜interconnection in the Purpose to ˜Bulk Electric System (BES) Issue: R3: The statement Transmission Operators that are known or expected to be affected the use of known or expected is redundant. Recommend removing ˜known or expected and have the requirement rewritten as follows: Issue: R3: Each Transmission Operator shall inform its Reliability Coordinator

Organization	Yes or No	Question 1 Comment
		and Transmission Operators to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. Issue: R8: The statement its internal area reliability should be clarified to state: R8: Each Transmission Operator shall inform its Reliability Coordinator of each of its SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its Transmission Operators area based on its assessment of its Operational Planning Analysis. Issue: M8: statement its internal area reliability should be clarified to state: has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you cant draw SOLs into the same category as IROLs unless you clearly indicate these standards only apply to a subset.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration. No change made. M1 and M4: Requirement language is usually repeated in Measures. No change made. Title has been corrected. Interconnection is the correct term in the Purpose, as Transmission Operators in different interconnections are not required to coordinate actions. The SDT sees no additional clarity from the suggested change. No change made.		

Organization	Yes or No	Question 1 Comment
The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made.		
Bonneville Power Administration	No	Comments: Given the potential uncertainty regarding the 30 Minute Rule, BPA suggests adding more clarity to the standard TOP-001-2 as the new draft could be interpreted to mean that one would need to get the flows below the SOL immediately. BPA believes this is not practical because it takes a definite amount of time to change schedules, move generation, or perform other actions in order to reduce loadings on facilities. BPA believes the new draft should include guidance as to how much time the BA or Transmission Operator would be allowed in order to reduce flows when there is an SOL violation. BPA suggests that more clarity be provided and/or the 30 minute rule be added back to the standard.
Response: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made. Additionally, the SDT believes including the "a violation of the Facility Rating or Stability criteria upon which it is based" is superior to how the standard is written today. The currently in force TOP-004-2, Requirement R2 is written without time limits or criteria and could be interpreted as requiring flows to be mitigated immediately for an IROL and SOL as well.		
ISO/RTO Standards Review Committee	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If

Organization	Yes or No	Question 1 Comment
		this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Southwest Power Pool Reliability Standards Development Team	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency

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ISO New England Inc.	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no

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BGE	No	BGE concurs with ISO/RTO Standards Review Committee Position:Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For

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		example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7.We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Pepco Holdings Inc	No	PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Nebraska Public Power District	No	Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is possible for the listed entities to have multiple TOPs. In R3, suggest rewording as "Each Transmission Operator shall inform its Reliability Coordinator, and other Transmission Operators, of each actual and anticipated Emergency that they are known or expected to be affected by, based on its assessment of its Operational Planning Analysis". The

Organization	Yes or No	Question 1 Comment
		existing language doesn't clearly specify what is to be communicated with affected entities. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9, even in situations where the inititating event was outside of design criteria. Current language allows exceedance of an IROL for a specific time, but does not appear to give any time to readjust the system for the less severe SOLs. This does not seem reasonable. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8?This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? Suggest "Each Transmission Operator shall inform its Reliability Coordinator of each SOL identified by the Transmission Operator as supporting the reliability of its Transmission Operator Area". With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC.

Organization	Yes or No	Question 1 Comment
		Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.

Response: R1: The SDT agrees and has adjusted the language to allow for multiple TOPs.

> **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless ~~-~~such actions would violate safety, equipment, regulatory, or statutory requirements.

R3: The SDT does not see that the suggested change improves clarity. No change made.

R9: SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. Additionally, if the SOL was not identified in Requirement R8, then Requirement R9 does not apply to it. No change made.

R8 and R9: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. The subset of SOLs in this requirement was created in response to industry comments that SOLs should not be completely removed from the standard.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R10 and R11: Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made.

R6: The SDT agrees. Conforming change made.

> **R6**. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.

Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-

Organization	Yes or No	Question 1 Comment
003-2, Requirements R1 and R2 which will be 10 months.		
Imperial Irrigation District (IID)	No	R2 - This requirement requires the BA, GOP, and LSE to notify the TOP if it cannot comply with the Reliability Directive. (Comment) - Should include the language that the entity is not able to comply with the Reliability Directive due to violation of safety, equipment regulatory or statutory requirements. R7 - This requirement requires that the TOP not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL (Comment) - Should the language in the requirement also include the reference to SOLs since WECC does not have IROLs? R8 - This requirement requires the TOP to inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis (Comment) - Remove “which, while not IROL” from the requirement language and add “that” before “have been identified”. This would make the statement more clear. R9 - This requirement requires that the TOP not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. (Comment) - Define Continuous. What would constitute a violation? 5 minutes, 10 minutes? In some cases corrective action requires participation and/or direction from the Reliability Coordinator and this could take up to 30 minutes. Recommend leaving the 30 minute duration in place. (Comment) - Recommend referencing R7 if the SOLs are included in the requirement. R10 - This requirement requires the TOP to inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each

Organization	Yes or No	Question 1 Comment
		SOL identified in Requirement R8, has been exceeded. (Comment) - the language should include the reference to R7 if the SOL is included in the requirement. (Comment) - Recommend including ~~time frame~~timeframe for notification to the Reliability Coordinator to include "30 minutes or less" R11 - This requirement requires the TOP to act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Measures or of an SOL identified in Requirement R8. (Comment) - Since only the Reliability Coordinator has the authority to direct others to take action; should the language be revised in the following manner; "The TOP shall take action to mitigate both the magnitude and duration of exceeding an IROL or an SOL as identified in R7 and R8 that occur within its TOPs area. The TOP shall appeal to the Reliability Coordinator to direct other TOPs in mitigating both magnitude and duration on interconnected facilities on the Bulk electric System".

Response: Requirement R2 covers all situations where the Reliability Directive can't be carried out. This requirement is simply to 'inform' and at the time in question the reason is not critical. The reason can be sorted out later. No change made.

In view of the current NERC definitions of IROLs and SOLs, the language is correct as is. The definition of IROLs describes the negative results that could occur when an IROL is exceeded for a time greater than its T_V. The definition for SOL does not have this language, so no "... instability, uncontrolled separation(s) or cascading outages...." happens upon the exceedance of an SOL that is not an IROL. No change made.

The SDT disagrees and believes the requirement needs to be clear that it applies to non-IROL SOLs since IROLs by definition are a subset of SOLs. However, the language in Requirement R8 was modified for improved clarity due to other comments.

> **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

Ratings include the element of time. 'Continuous duration' has its common meaning. The SOLs in question are in reference to Requirement R8, not Requirement R7. The SDT received a substantial amount of comments during the last posting to remove the

Organization	Yes or No	Question 1 Comment
30 minute timeframe on SOLs. No change made. The SOLs in question are in Requirement R8 which is referenced in Requirement R10. No change made. Requirement R10 notification is after the fact and no timeframe is necessary. No change made. One Transmission Operator can reach out to another Transmission Operator in Requirement R11 and it would be expected that the other Transmission Operator would respond per Requirement R4. The Reliability Coordinator always maintains ultimate responsibility for multi- Transmission Operator areas as per the IRO standards and would be expected to step in as needed. This set of requirements is not a procedure. No change made.		
Kansas City Power & Light	No	Requirements R3 & R5 requires TOP's to notify all other "affected" TOP's in instances of emergency or Adverse Reliability Impact. The term "affected" is a debatable condition and subject to interpretation. As proposed, this requirement will be difficult to audit and will cause uncertainty in the industry. Recommend the requirement be modified to alert other TOP's whenever a TOP in an emergency or Adverse Reliability Impact operating condition becomes aware of operating conditions that would result in exceeding an SOL or IROL operating limits under N-1 contingency conditions for other TOP facilities. Modifications for these two requirements will result in subsequent changes to the Measures and VSL's for requirements R3 & R5. In requirements R9 and R11 the 30-minute transition from an unknown operating state to a known state is lost for operating from an n-1 state to a n-2 state therefore leading to an immediate violation of R9 if the facility rating is exceeded. Also, the inclusion of IROL's in R10 and R11 makes these requirements confusing as to who is responsible for mitigation, IROL's should be removed from here as they are considered in the IRO requirements, these requirements should only address SOL's. Requirement R8 uses the term "continuous duration". The term "continuous duration" will be subject to interpretation as to its meaning and intent. As proposed, this requirement will be difficult to audit and will cause

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>uncertainty in the industry.

Also, a draft Reliability Directive definition is included in this standard but needs approval in the COM-002 standard, what if COM-002 does not get approved?</td></tr>
<tr><td colspan="3">Response: The SDT believes the use of the defined terms in the requirements covers the situation appropriately. No change made.

By definition an IROL violation occurs when the IROL limit is exceeded for duration greater than T_v. Thus, it must be the time duration. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made.

Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made.

This is actually referring to Requirement R9, not Requirement R8. 'Continuous duration' has its common meaning. No change made.

Reliability Directive: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will also be coordinated with that team.</td></tr>
<tr><td>SERC OC Standards Review Group</td><td>No</td><td>We suggest that the definition of Reliability Directive should be modified as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or “an event that results in Bulk Electric System instability or Cascading”. We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition.

We suggest the Standard Drafting Team further clarify or define the term “supporting internal area reliability” as an aid in demonstrating compliance and how this requirement enhances reliability.</td></tr>
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<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>We suggest including “Real-time Assessments” in this standard to clarify Operations Planning and same day operations time horizons (Requirement 8).

We request that the drafting team review and explain the differences in the time horizons for Requirements 3, 5 and 8.</td></tr>
<tr><td colspan="3">Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration. No change made.

The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

A Transmission Operator cannot operate with its IROLs (Requirement R7) and SOLs (Requirement R9) without performing Real-time assessments. As a result, the SDT does believe that Real-time assessments are included. No change made.

Requirement R3 is day ahead so the horizon is operation planning. Requirement R5 is in real-time so the horizons represent those time horizons. Requirement R8 should be Operations Planning only and the SDT has made this change.</td></tr>
<tr><td>MRO-NSRF</td><td>No</td><td>Issue: Upon review of the NERC Glossary of Terms, please drop the “s” from “...or Adverse Reliability Impacts” within the definition of a Reliability Directive.

Issue: M1; It is not necessary to repeat the Requirement within the Measure. Recommend “unless such actions would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1”, be removed from this Measure.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		Issue: M4; It is not necessary to repeat the Requirement within the Measure. Recommend "unless such actions would violate safety, equipment, regulatory, or statutory requirements", be removed from the Measure. Issue: Upon review, it is noted that 'Coordination of' has been struck from Purpose, however not removed from the Title of the Standard. Recommend changing 'interconnection' in the Purpose to 'Bulk Electric System (BES)' Issue: R3: The statement "...Transmission Operators that are known or expected to be affected..." the use of "known or expected" is redundant. Recommend removing 'known or expected' and have the requirement rewritten as follows: Issue: R3: Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. Issue: R8: The statement "...its internal area reliability..." should be clarified to state: R8: Each Transmission Operator shall inform its Reliability Coordinator of each of its SOLs which, while not IROLs, have been identified by the Transmission Operator as supporting its Transmission Operators area based on its assessment of its Operational Planning Analysis. Issue: M8: statement "...its internal area reliability..." should be clarified to state:"...has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis..." Issue: Please clarify on the issue of SOLs. IROLs have a time limit but SOLs do not. Is the SDT requiring no SOL limit(s) are to be violated? What is the criteria and basis to R8 and R9. Note that the SOL definition has a thermal rating component in it and we are not sure how you can't draw SOLs into

Organization	Yes or No	Question 1 Comment
		the same category as IROLs unless you clearly indicate these standards only apply to a subset.
Response: "Reliability Directive" is under the auspices of the RC SDT (Project 2006-06). This comment has been passed on to that team. Plural versions of the NERC definitions are regularly used throughout the standards. M1: Requirement language is usually repeated in Measures. No change made. M4: Requirement language is usually repeated in Measures. No change made. R3: The SDT sees no additional clarity from the suggested change. No change made. R8: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. SOLs: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made.		
Constellation Energy	No	The definition of Reliability Directive is an improvement but the definition must capture the identification concept that is reflected in the Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. We suggest the following revision to the definition and it should follow through to Project 2006-06 (COM-002-3 and IRO-001-3), eventually being added to the Reliability Standards Glossary of Terms. A communication identified as a Reliability Directive by a Reliability Coordinator, Transmission Operator, or Balancing Authority to initiate action by the recipient to address an Emergency or Adverse Reliability Impact. The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. CCG, CECD and CPG agree with ISO/RTO Standards Review Committee Position: Instead of using 'its' TOP in R1 we suggest using 'a' TOP since it is

Organization	Yes or No	Question 1 Comment
		possible for the listed entities to have multiple TOPs. R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't identified in R8? This brings us to the issue of R8. R8 is unclear. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well

Organization	Yes or No	Question 1 Comment

Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.

The SDT agrees and has adjusted the language to allow for multiple Transmission Operators.

> **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless ~~-~~such actions would violate safety, equipment, regulatory, or statutory requirements.

By definition an IROL violation occurs when the IROL limit is exceeded for a duration greater than T_v. Thus, it must be the time duration. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made.

Requirement R9 does not apply to SOLs which are not identified in Requirement R8. No change made.

The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

The subset of SOLs in this requirement was created in response to industry comments. No change made.

Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made.

The SDT agrees.

> **R6**. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated

Organization	Yes or No	Question 1 Comment
communication channels between the affected entities. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Detroit Edison	Negative	The requirement to notify all negatively impacted interconnected NERC registered entities of planned telemetry outages is overly burdensome. Many small generators could technically be impacted, yet not very meaningful impact on a cumulative basis.
Response: The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.		
ACES Power Marketing Member Standards Collaborators	No	We largely agree with the changes but have identified the following specific issues. We disagree with removing Bulk Electric System (BES) from the purpose of the standard. NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Substituting BES for “interconnection” in the purpose statement may solve this issue. While the title contained in the header was changed to “Transmission Operations” the actual title was not changed. They should match. For simplicity, we recommend striking “known or expected to be” from

Organization	Yes or No	Question 1 Comment
		Requirement R3. As it is written now, it is more confusing. First, the TOP, can only notify other TOPs that it knows are affected. Second, the use of "expected" implies that something different is meant than known. If so, what is the intention of the meaning and whose expectation is it: the responsible TOP, the other TOP, the auditor or some other entity? There is a similar issue regarding "known or expected to result in an Adverse Reliability Impact" in Requirement R5. We recommend striking "or expected" for simplicity and to avoid the confusion of whose expectation it is. In Requirement R8, "while not IROLs" should be "while not an IROL". We agree with removing the 30 minute limit in Requirements R9 and R11 and basing the time limit upon the Facility Rating or Stability criteria. In Requirement R10, striking "each" before SOL would improve the clarity of the requirement. In Measurement M1, "nless" should be unless. This may already be correct. The red-lines show "nless" and the clean document shows "unless". What is the intended difference between Transmission Operator Area in Requirement R5 and internal area in Requirement R8? Should they be the same and if not why not?
Southwest Transmission Cooperative, Inc.	Affirmative	We disagree with removing Bulk Electric System (BES) from the purpose of the standard. NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader

Organization	Yes or No	Question 1 Comment
		than the BES, we would like to see BES inserted back into the purpose statement. Substituting BES for "interconnection" in the purpose statement may solve this issue. While the title contained in the header was changed to "Transmission Operations" the actual title was not changed. They should match. For simplicity, we recommend striking "known or expected to be" from Requirement R3. As it is written now, it is more confusing. First, the TOP, can only notify other TOPs that it knows are affected. Second, the use of "expected" implies that something different is meant than known. If so, what is the intention of the meaning and whose expectation is it: the responsible TOP, the other TOP, the auditor or some other entity? There is a similar issue regarding "known or expected to result in an Adverse Reliability Impact" in Requirement R5. We recommend striking "or expected" for simplicity and to avoid the confusion of whose expectation it is. In Requirement R8, "while not IROLs" should be "while not an IROL". We agree with removing the 30 minute limit in Requirements R9 and R11 and basing the time limit upon the Facility Rating or Stability criteria. In Requirement R10, striking "each" before SOL would improve the clarity of the requirement. In Measurement M1, "nless" should be unless. This may already be correct. The red-lines show "nless" and the clean document shows "unless". What is the intended difference between Transmission Operator Area in Requirement R5 and internal area in Requirement R8? Should they be the same and if not why not?

Response: BES: The purpose of the standard is to address reliability needs. Any concerns about BES vs. BPS in standards are

Organization	Yes or No	Question 1 Comment
better directed toward the Standards Committee. No change made. Title: Conforming change has been made. R3: The SDT sees no additional clarity from the suggested change. No change made. R5: The SDT sees no additional clarity with the suggested change "known or expected to be affected". This language was chosen to cover all situations, including an ongoing event. No change made. R8: The SDT agrees. **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. The SDT thanks you for your support on removal of the 30 minute limit. R10: The SDT agrees and made the conforming change. **R10**. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or ~~each~~an SOL identified in Requirement R8, has been exceeded. M1: This has been corrected. In response to this and other comments, Requirement R8 has been edited to match the language in Requirement R5.		
Lincoln Electric System (LES)	No	R4 in TOP-004-1 provided a 30-minute transition from an unknown operating state to a known operating situation. Although the SDT has indicated they included a provision for that transition in R7 and R9 of TOP-001-2 some flexibility is still lost. For example, if you are operating with no N-1 contingency violations and a contingency occurs, the next contingency (N-2 from the original state) could cause a violation of a Facility Rating. If this contingency actually occurs, then loading immediately exceeds the Facility Rating and you are in violation of R9. Previously, we would have had 30 minutes to work with this condition before being in violation. Additionally, R9 only applies if the SOL is identified in R8. What if it isn't

Organization	Yes or No	Question 1 Comment
		identified in R8? R8 is unclear as currently drafted. What is meant by 'internal area reliability'? How does it differ from reliability of a TOP Area as included in R5? With the inclusion of internal area reliability in R8 and R9, aren't these requirements now in conflict with the purpose of the standard which is directed toward impacts on the reliability of the interconnection? Including IROLs in R10 and R11 introduces confusion regarding who's responsible for mitigating IROLs - the RCs or the TOPs. Therefore the SDT should give consideration to removing the references to IROLs in these requirements and defer to IRO-001-2, R7. We would suggest using 'its' RC in R6 rather than 'the' RC. Finally, why is the effective date set at 24 months following approval since there are basically no new requirements associated with this standard? Most all of the changes are primarily clarification or consolidation.

Response: R7 and R9: By definition an IROL violation occurs when the IROL limit is exceeded for a duration greater than T_v. Thus, it must be the time duration. SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. No change made.

Requirement R9 does not apply to SOLs which are not identified in Requirement R8. No change made.

R8: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8.

> **R8**. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R8 and R9: The subset of SOLs in this requirement was created in response to industry comments, resulting in no conflict with the purpose of the standard. No change made.

R10 and R11: Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to

Organization	Yes or No	Question 1 Comment
handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made. R6: The SDT agrees. **R6**. Each Balancing Authority and Transmission Operator shall notify ~~the~~its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
Progress Energy	No	Progress, while supporting what we believe is the overall intent of this Standard revision, cannot support an affirmative vote on TOP-001-2. Progress appreciates the efforts of the SDT and offers the following suggestions: In R8 it remains unclear what is meant by the phrase “supporting its internal area reliability.” Clarity and unambiguous language is needed here so that entities can clearly understand and comply with the requirement. Progress understands from reading the most current “Consideration of Comments” that the Standard Drafting Team left this phrase intentionally undefined; however, the inclusion of this phrase means that in an audit scenario there could be a disagreement about what “supporting its internal area reliability” means. This has the potential to negatively impact the compliance position of the Transmission Operator. In R9 it is unclear what is meant by a “continuous duration that would cause a violation...” Some entities may have facility ratings that are time based, while other entities take the position that the exceedance of a facility rating for any amount of time means an SOL violation. A suggested change in wording would be to simplify the requirement to read “Each Transmission Operator shall not operate outside any SOL indentified in Requirement R8 that would cause a violation of the Facility Rating or Stability criteria upon

Organization	Yes or No	Question 1 Comment
		which it is based." Progress suggests changing R10 to read "Each Transmission Operator shall inform its Reliability Coordinator of the mitigation actions it has taken or directed to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded." The current draft language implies that the TOP must only inform the RC of "...its actions..." Progress suggests switching the order of the current R10 and R11; from reading the most current "Consideration of Comments" it seems that the actions required in R8-R11 are intended to be sequential. Progress suggests that switching the order of the current R10 and R11 would make it easier for a reader to understand that these are intended to be sequential actions.
Response: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. Ratings include the element of time. Continuous duration' has its common meaning. The phrase "for a continuous duration" was added in response to industry comments. No change made. The SDT believes the requirement mandates that the Transmission Operator inform of any actions which would include directions to others and sees no additional clarity with the suggested change. No change made. This is not a procedure and the order of the requirements doesn't matter. There is no additional clarity provided by the suggested change. No change made.		
LG&E and KU Serivces	No	LG&E and KU Services believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This

Organization	Yes or No	Question 1 Comment
		is a Reliability Directive." to avoid any possibility of confusion.
Response: The definition does not include the regulated action. Requirement R1 states that it must be identified. The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.		
City Water Light and Power (CWLP) - Springfeild – IL	No	R8 requirement to identify "...SOLs which...have been identified by the Transmission Operator as supporting its internal area reliability based on its assessment of its Operational Planning Analysis" is vague and difficult to measure. "Internal area reliability" could conceivable include all SOLs CWLP echoes SERC Operating Committee comments submitted separately:" We suggest that the definition of Reliability Directive should be modified as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or "an event that results in Bulk Electric System instability or Cascading". We also recommend that the Standard Drafting Team coordinate with the COM-002-3 Standard Drafting Team to ensure consistency in the Reliability Directive definition."
Response: The phrase 'internal area reliability' was replaced in Requirement R8 and a conforming change was made in Measure M8. If the Transmission Operator believes it needs to include all of its SOLs, the requirements do not preclude them from doing so. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.		
United Illuminating Company	No	R3 phrase "known or expected to be affected by each actual and anticipated

Organization	Yes or No	Question 1 Comment
		Emergency based on its assessment of its Operational Planning Analysis" is confusing. Glossary defines emergency as Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System. Glossary defines Operation Planning analysis as An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints(transmission facility outages, generator outages, equipment limitations, etc.).I do not see the difference between TOPs KNOWN to be effected by an anticipated Emergency from those EXPECTED to be effected by an anticipated Emergency. The Requirement should state TOP's expected to effected by an anticipated Emergency. Those TOP's known to be effected are part of the group expected to be effected. Operations Planning occurs in the Day ahead. An actual Emergency cannot occur in the Day Ahead. The word actual should be removed. The SDT should scope R3 to the concept of Operational Planning as defined in the Glossary. Along the thought the Time Horizon in the Requirement is Operations Planning. I suggest rephrasing this requirement as:R3. Each Transmission Operator shall inform its Reliability Coordinator and those Transmission Operators that are expected to be affected by an anticipated Emergency based on its assessment of its Operational Planning Analysis. Comment for R8. It seems that double jeopardy is introduced with TOP-001 R8 and FAC-011 R5.2. Fac-011 R 5.2 states The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area; while TOP-001 R8 states R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal

Organization	Yes or No	Question 1 Comment
		area reliability based on its assessment of its Operational Planning Analysis.
Response: The SDT sees no additional clarity with the suggested change. No change made. The subset of SOLs in this requirement requires special handling (an incremental requirement to FAC-014-2, Requirement R5.2), thus, this requirement does not introduce double jeopardy. While FAC-014-2, Requirement R5.2 requires the Transmission Operator to provide all of the SOLs it developed to the Reliability Coordinator, proposed TOP-001-2, Requirement R8 requires the Transmission Operator to further sub-divide those SOLs into those that require special handling in this standard. No change made.		
California Independent System Operator	No	R6 requires Balancing Authorities and Transmission Operators to notify "negatively impacted interconnected NERC registered entities" of planned outages. This term is not specific enough to narrow down who must be notified. For instance, with this open-ended wording it could be construed that BAs would have to notify LSEs and DPs in their areas which would be an onerous task. We would recommend staying with "negatively-affected BAs and TOPs." The wording in R9 is confusing and is not specific enough to ensure compliance. In particular the requirement prohibits operation outside any SOL "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based." However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. In addition, under R9 and M9, how will the word "continuous" be defined or measured? This is extremely important to understand because the VSL table states the following as Severe for R9: "The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria." It seems that the effective date should be set much sooner than 24 months following approval since there are basically no new requirements associated

Organization	Yes or No	Question 1 Comment
		with this standard. Most all of the changes are primarily clarification or consolidation. This comment applies to TOP-002-3 and TOP-003-2 as well.
Response: R6: The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made. R9: 'Continuous duration' has its common meaning. No change made. Regarding the effective dates, the SDT agrees, and has shortened the effective date to 12 months except for the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
We Energies	No	R3's wording is incomplete. It requires informing and states who must be informed but does not state what must be told. The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP's BA(s) of an Emergency. Should also include the BA informing its RC and TOP(s) R4 It is not clear what emergency assistance a TOP can provide? Most actions would involve moving a generator or shedding load, the few items a TOP can do independently like returning a line from outage, or switching reactive devices should be done as a matter of course. R5 The bulk of the requirement is a description of which RCs and TOPs must be informed, but lacks informing the TOP's BA(s) of an operation resulting in an Adverse Reliability Impact. Should also include the BA informing it's RC and TOP(s) R6 is overly broad. Every entity in an interconnect can be negatively impacted somehow. The requirement should be focused on the operational

Organization	Yes or No	Question 1 Comment
		entities of the TOP, BA and RC. These are the entities that specify the data that must be made available see IRO-010, proposed TOP-003 from others. Individual asset owners provide data to the operators and when the operators plan an outage they should let the other affected TOP, BA and RC know its to happen. R8: change “have” to “has”. The associated measures should be updated to reflect the above. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.

Response: R3: The SDT does not see that the suggested change improves clarity. The requirement indicates that the recipients must be told about the effect on them of an actual or anticipated emergency. No change made.

R4: The Transmission Operator has actions that it may take or direct such as switching, bringing on capacitor banks, delaying maintenance, etc. All of these are possible emergency assistance actions.

R5: Requirement R5 is for transmission so the Balancing Authority can't be included (Balancing Authority’s have no transmission information). No change made. Approved EOP-002-3, Requirement R3 covers the situation for a Balancing Authority needing to inform others of impacts. No change made.

R6: The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.

R8: The SDT agrees.

> **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

Measures: Conforming changes were made to measures.

Organization	Yes or No	Question 1 Comment
Data Retention: The SDT agrees and has deleted the compliance phrasing.		
American Transmission Company, LLC	No	o If the definition of "Reliability Directive" remains, the Definitions of Terms Used in the Standard should note that there is in fact a new or revised definition. ATC agrees with the definition. o Requirement 4 - This should have a control by the Reliability Coordinator to ensure that a Transmission Operator in distress has, in fact, implemented their "comparable emergency procedures". o Requirement 5 - ATC does not agree with removing the BA from this requirement since they make note that it will be addressed in another, "proposed" requirement as stated in the mapping document. o Requirement 7 - Real-Time EMS representation of IROL Tv, will require an unidentifiable amount of resources. o Requirement 9 - SOL's should have a time requirement. Also, they should not be raised to the level of IROL's as may be insinuated by this requirement if they are discretionary, as noted in Requirement 8. o Requirement 11 - If this requirement entails the issuing of a "Reliability Directive", it should be stated as such.
Response: Reliability Directive: This standard does identify this definition as a new definition that is being developed by Project 2006-06. It also mentions that the RTO SDT is coordinating with that project. R4: In the context of mandatory standards, no Reliability Coordinator control is needed. No change made. R5: The Balancing Authority did not appear in Requirement R5 so the SDT does not understand the comment. No change made. R7: It is common practice in the industry to have ratings with both magnitude and duration. The SDT understands that there are relatively few IROLs, and does not expect a significant burden on the Transmission Operator to be able to comply with this requirement. Also, the requirement does not dictate the technological tools used in assuring compliance. No change made. R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. Some SOLs are based		

Organization	Yes or No	Question 1 Comment
off of Facility Ratings and, thus, include the time dimension. It is to the Transmission Operator's discretion to select the appropriate SOLs in Requirement R8 that it feels need to be treated like this. No change made. R11: This requirement does not have to specify how an instruction is issued. No change made.		
Omaha Public Power District	No	OPPD is concerned with Requirements (R8 and R9) related to System Operating Limits (SOLs). We would like to ask the SDT to clarify what the word "continuous duration" means in terms of timing. We understand the "continuous duration" is based on Facility Rating or Stability criteria, however, without any defined time frame, the term "duration" would be subject to variety of interpretations. OPPD supports a time window to allow TOP to return from SOL similar to IROL Tv.
Response: SOLs are tied to the facility ratings which contain a time element which may or may not be 30 minutes. 'Continuous duration' has its common meaning. It is to the Transmission Operator's discretion to select the appropriate SOLs in Requirement R8 that it feels need to be treated like this. No change made.		
Manitoba Hydro	No	R1 - Manitoba Hydro suggests that the first instance of 'identified' in R1 be removed as it is redundant given that R1 already specifies that the Reliability Directive is 'identified as such'. As drafted, the standard suggests that there is a difference between an 'identified Reliability Directive' and a 'Reliability Directive'. Data Retention (1.3) – The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified logs, recordings and emails, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit. This comment applies to TOP-001-2, TOP-002-3, and TOP-003-1.

Organization	Yes or No	Question 1 Comment
Response: The SDT agrees and has deleted the first instance of 'identified'. **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless -such actions would violate safety, equipment, regulatory, or statutory requirements. Data Retention: The language in the 1st paragraph is boilerplate that is inserted in all standards. Compliance language is not under control of SDT. No change made.		
Texas Reliability Entity	No	In R1, the phrase “and identified as such” is redundant and unnecessary in that “identified” already exists within the sentence. Furthermore, the addition of the word “identified” or phrase “identified as such” inserts undue ambiguity and complication, and we are concerned that the “identified” concept will actually provide more opportunities for miscommunications during tense situations. In R1, we are concerned that “Directive” is being proposed with descriptive terms (e.g., “reliability”), and if the descriptive terms are not used explicitly an entity may not be compelled to act accordingly (also may provide leverage for a perceived loophole in compliance activities that could be exploited-“I was unaware it was a {insert descriptive term} Directive”). There should be a time frame associated with requirement R2. Perhaps add “within the timeframe determined for the Directive being issued” to end of sentence. Also, we suggest removing “identified” from requirement R2 (see comments on R1). oThere should be a time frame associated with the communication required by Requirement R5. oR5 should explicitly include IROL, SOL, and Stability Limit violations in the examples since the proposed definition of Adverse Reliability Impact implies

Organization	Yes or No	Question 1 Comment
		instability and Cascading outages. oWe suggest rewriting R5 as follows: "Each Transmission Operator shall inform its Reliability Coordinator and other affected Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas within a timeframe that is sufficient for the RC and affected TOP's to respond to the system condition, unless conditions do not permit such communications. Such operations may include, but are not limited to, Interconnection Reliability Operating Limit (IROL) violations greater than Tv, System Operating Limit (SOL) violations, Stability Limit violations, relay or equipment failures, and changes in generation, Transmission, or Load." In R9, the use of "continuous duration" in the revised language is confusing and should be removed. It would be better to clearly rely on the other standards that relate to identifying IROLs and SOLs (including duration limits), which may have multiple time limits associated with various operating conditions. We note that an SOL may not be based on a single Facility Rating but may actually be a group of Facilities aggregated into a single limit. We suggest saying: "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria, including duration, upon which it is based".

Response: The SDT agrees and has deleted the first instance of 'identified'.

> **R1**. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~identified~~ Reliability Directive issued and identified as such by its Transmission Operator(s), unless ~~-~~such actions would violate safety, equipment, regulatory, or statutory requirements.

Some instructions are more important than others. In order to separate these more important instructions from those for routine actions, the descriptive 'adjective' is required so that the receiving entity understands the importance of the instructions. Reliability Directives are of such importance that the actions taken must conform exactly to the instructions as opposed to routine operating instructions which may allow for some discretion. If this isn't made clear during the event, then it is not a Reliability

Organization	Yes or No	Question 1 Comment
Directive. This is not a loophole and is consistent with the recent Board of Trustees adopted interpretation of COM-002-2 that makes clear that directives are intended for emergencies only. No change made. The Reliability Directive in question will include the timeframe for the response if one is needed. No change made. The term 'identified' was included in Requirement R2 in response to industry comments that all Reliability Directives must be identified as such. No change made. This SDT and others have worked with various phrases to indicate a timeframe, however, after extensive investigation, it has been determined that no phrase is both consistent with reliable operations while also crisp enough to provide reassurance to the regulated entity that it may avoid noncompliance. The requirement is to inform. It implies that the information must be communicated to the other entities within a timeframe that enables them to respond (if possible). No change made. R5: The examples are not types of violations but types of operations. No change made. R9: 'Continuous duration' has its common meaning. No change made.		
New York Independent System Operator	No	Communications must be a well defined, consistent and established process to promote clear and accurate communications between operators for both normal and emergency conditions. This standard could be interpreted as to require an extra phrase during emergencies that would unnecessarily complicate communications. The requirement is reasonable if the identification of a 'Reliability Directive' may be done in a policy or procedure that is communicated to the BA, GOP, DP or LSE as a communication protocol that addresses normal and emergency communications. Otherwise requiring different verbal communication protocols for normal or emergency conditions will add a level of risk currently not observed.
Response: The SDT disagrees that including a simple statement that this is a Reliability Directive complicates communications. In fact, the SDT thinks it improves communications because the recipient understands it must follow the Reliability Directive explicitly. There is nothing in this standard that prevents an entity from adopting formal communication protocols to always identify directives as such to ensure consistent and uniform communications. No change made.		

Organization	Yes or No	Question 1 Comment
Xcel Energy	No	R1. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall comply with each identified Reliability Directive issued by its Transmission Operator, unless the respective entity informs its Transmission Operator that such actions would violate safety, equipment, regulatory, or statutory requirements. We would like to see additional clarification to clarify “equipment”, suggest using “equipment limitation” or “equipment rating” R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. This requirement should be modified so as not to place the burden on the assisting entity to demonstrate that the requesting entity has implemented “comparable emergency procedures”. Suggest the following language: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, unless such actions would violate safety, equipment ratings, regulatory, or statutory requirements. R5. Each Transmission Operator shall inform other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. This requirement appears to duplicate PRC-001-1 R2 and R5. It is assumed, but cannot be verified that those requirements will be eliminated in a future approved version of that standard. R9 - We appreciate the drafting team’s efforts. However, we are still concerned that R9 will not allow the Transmission Operator the flexibility to identify the best SOL recovery approach, without incurring a violation of the

Organization	Yes or No	Question 1 Comment
		requirement. Instead, the TOP may be forced to shed load in order to avoid violating the requirement. This is not ideal, especially when the situation could be mitigated successfully with alternative measures. It is not clear if an entity is allowed to use an RC-approved contingency plan to mitigate a situation that would cause a Facility Rating violation (i.e. the Facility Rating is the SOL), without also incurring a violation of R9. To further explain, if an entity foresees exceeding an SOL in its OPA, and obtains approval from the RC on their proposed contingency plan (which includes a Facility Rating violation), will that entity be considered in violation of R9 once the exceedance occurs and the contingency plan is implemented? R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or each SOL identified in Requirement R8, has been exceeded. This requirement should specify a sustained period which establishes when it is considered that the entity has returned below the limit (or some other value so as to not misconstrue momentary recoveries as meeting this requirement).

Response: R1: All terms are descriptors of the word 'requirements' so the SDT believes that your concerns have been met with the existing language. No change made.

R4: Industry comments caused the SDT to insert the 'comparable' language. No change made.

R5: The SDT is proposing to retire PRC-001-1 Requirements R2, R5, and R6. A redline of PRC-001-1 will be posted with these comments.

R9: Ratings include the element of time, that is, ratings are two dimensional, with a magnitude limit and time (duration) limit. 'Continuous duration' has its common meaning. The flexibility remains within these requirements to have a mitigation plan in place. However, the mitigation plan must avoid causing a ratings violation (avoid exceeding the magnitude limit for greater than T_v), else, it would be a violation of this requirement. No change made.

R10: Requirement R10 is about actions taken by the Transmission Operator and not about relief attained. That is covered in the IRO standards. Therefore, no change is necessary.

Organization	Yes or No	Question 1 Comment
ReliabilityFirst	No	ReliabilityFirst has the following comments for consideration: 1. Definition of Reliability Directive - ReliabilityFirst believes there could be a possible issue with the definition of "Reliability Directive" being developed and approved via another drafting effort (i.e. Project 2006-06). In the hypothetical situation where the TOP-001-2 standard is approved and the definition of "Reliability Directive" is drastically changed through the Project 2006-06 effort, there could possibly be a disconnect between the TOP-001-2 requirements and the "Reliability Directive" definition. Also, ReliabilityFirst recommends adding a parenthetical "(e.g. IROL or SOL violations)" to the end of the definition for further clarity. 2. R2 - There is no time qualifier specified in R2 dealing with the timeframe in which the applicable entity has to inform its Transmission Operator of its inability to perform an identified Reliability Directive. ReliabilityFirst recommends the SDT consider adding language to include a timeframe for the entity to inform the Transmission Operator (such as one hour). Absent any specified timeframe, an applicable entity could hypothetically inform its Transmission Operator of its inability to perform an identified Reliability Directive 30 days after the Reliability Directive was issued, and still be compliant based on the current words of the requirement. 3. R4 - The term "emergency" is used within this requirement and ReliabilityFirst seeks clarification on whether this is referring to the NERC definition of "Emergency" (as defined in the NERC Glossary of terms)? If so, this term should be capitalized. 4. R5 - The last sentence in R5 is not really a requirement, but rather a measure on how to comply with the requirement. ReliabilityFirst recommends deleting the last sentence of R5 and incorporating it into the corresponding Measure. 5. R6 - ReliabilityFirst recommends removing the term "negatively impacted

Organization	Yes or No	Question 1 Comment
		interconnected NERC registered entities" and replace it with the associated functional entities (e.g. Balancing Authority, Generator Operator, etc.). 6. R8 - ReliabilityFirst recommends removing the term "while not IROL's" from R8. SOL is a NERC defined term and the extra qualifier is not needed. 7. R10 and R11 - ReliabilityFirst recommends swapping the order of R10 and R11. From a chronological standpoint, the Transmission Operator will "act or direct others to act, to mitigate..." (R11) prior to "informing its Reliability Coordinator of its actions" (R10). 8. Data retention - ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the last sentence states "the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.

Response: Reliability Directive: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team also. This comment will be passed to that team for consideration.

The Reliability Directive in question will include the timeframe for the response if one is needed. No change made.

The NERC defined term "Emergency" was not the intent of this requirement. In this requirement, 'emergency' means actions taken quickly in response to an immediate need. No change made.

The last sentence in Requirement R5 is intended to provide guidance on the kinds of operations that should be communicated and is better kept in the requirement. No change made.

If the entities were listed, the list would include every NERC functional entity that has telemetry. This change would not improve

Organization	Yes or No	Question 1 Comment
reliability. No change made. IROLs are a subset of SOLs as defined by NERC. The requirement concerns a different subset of SOLs. No change made. This is not a procedure and the order of the requirements doesn't matter. There is no additional clarity provided by the suggested change. No change made. Data Retention: The language in the 1st paragraph is boilerplate that is inserted in all standards. The compliance language is not under control of SDT. No change made.		
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agecy supports comments submitted by the SERC OC Standards Review Group and the ISO/RTO Standards Review Committee concerning the need to address the “Reliability Directive” definition in concert with COM-002-3.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration.		
Duke Energy	No	While the drafting team has made several improvements to this standard, we believe these additional changes are needed: o The definition of Reliability Directive includes the defined term “Adverse Reliability Impact”, which should be replaced by the actual wording of latest BOT-approved definition of “Adverse Reliability Impact”, since it has not yet been approved by FERC. If the SDT decides not to replace Adverse Reliability Impacts with the actual wording of the latest BOT-approved definition, then the SDT should delete the “s” from “Impacts”. o R8 - We believe that the phrase “supporting its internal area reliability” should be further clarified in some way. The inclusion of the undefined concept of “supporting internal area reliability” creates undue compliance risk, since auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”. The drafting team could examine the disturbance reporting criteria in EOP-004-1

Organization	Yes or No	Question 1 Comment
		Attachment 1 to help develop a reasonable threshold for reporting SOLs to the Reliability Coordinator. o R8 - Consistent with R3, the Time horizon for R8 should only be Operations Planning. o R9 - The change that has been made to R9 could be interpreted to result in a violation if a facility rating is exceeded for any amount of time at all. Similar to an IROL's Tv, SOLs identified under R8 should have an identified time period (such as 30 minutes) for mitigation without a violation. A change to R9 should be coupled with development of a reporting threshold for R8 as discussed above. o M1 - typo, left the "u" off the word "unless". o Measures for R8 and R9 should be changed consistent with our suggested revisions to the requirements.

Response: "Reliability Directive" is under the auspices of the RC SDT (Project 2006-06). This has been passed on to that team.

R8: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

> **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.

R8: The SDT agrees and has changed the Time Horizon to Operations Planning.

R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. No change made.

M1: This has been corrected.

Organization	Yes or No	Question 1 Comment
M8 and M9: Conforming changes were made to Measure M8. No changes were made to Requirement R9.		
South Carolina Electric and Gas	No	Please provide clarity on the phrase "support its internal area reliability" in R8.
Response: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Oklahoma Gas and Electric	No	A. In the draft TOP-001-2 standard, R1 and R2 both address complying with Reliability Directives. OG+E suggests these two requirements be combined into one requirement using similar language found in other standards that contain the same Reliablity Directive requirement, such as IRO-001-1.1 R8 and the previous version of this standard for consistency purposes. B. Mitigation of IROLs is ultimately the responsibility of the RC. TOPs act under the direction of the RC when mitigating IROLs. TOP-001-2 R11 should clarify by adding the following to the beginning of the requirement. "Under the direction of the RC, each TOP shall act or direct others to act...". C. Please clarify the meaning of "internal area realiability" in R8. D. In R9, "continuous duration" warrants additional clarification. Is this 5, 10, 30, 60 minutes of operating outside the SOL? Or only continuous operation outside of SOL that results in ultimately exceeding the Facility Rating?

Organization	Yes or No	Question 1 Comment
Response: R1 and R2: The SDT sees no additional clarity with the suggested change. No change made. R11: Normally the Reliability Coordinator would have developed a plan per approved IRO-009-1, Requirement R3 to handle these situations but the case in place here is for those immediate situations where the Transmission Operator must start to act while waiting for the Reliability Coordinator to act per approved IRO-009-1, Requirement R4. The Reliability Coordinator is always the responsible entity for IROLs and this requirement does not change that fact. No change made. R8: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. 'Continuous duration' has its common meaning. No change made.		
American Electric Power	No	R7, R9, R10, & R11 - It needs to be clarified whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader. Taken together, the combination of R7 and R9 appears redundant with R11, as meeting the objective of R7 and R9 would imply taking the proper mitigating measures. AEP suggests either eliminating both R7 and R9 or eliminating only R11. If r7 and R9 were to be eliminated, the references to magnitude and duration should be removed from R11, as the associated measure is binary

Organization	Yes or No	Question 1 Comment
		in respect to the limit, i.e., either the limit has been exceeded or it has not. It would be premature for AEP to support the associated VSLs and VRFs given the objections stated above.
Response: R7, R9, R10, and R11: The SDT agrees for SOLs, however, it must be noted that IROLs have been defined as both pre-contingent and post-contingent. The exact definition of the IROL must be honored. No change made. R7, R9 and R11: These requirements are the core Transmission Operator requirements that assure continued reliable operation of the BES. If the Transmission Operator acts or directs others to act to mitigate, as in Requirement R11, but the facility remains in violation of Requirements R7 or R9, then the Transmission Operator is compliant with Requirement R11 and noncompliant with either Requirements R7 or R9, as dictated by the exact circumstances. If the Transmission Operator fails to act or fails to direct others to act, as in Requirement R11, then it is noncompliant with both Requirement R11 and either Requirement R7 or R9, as dictated by the exact circumstances. This is not double jeopardy. No change made.		
PPL Electric Utilities	No	We believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
PPL EnergyPlus LLC	Affirmative	We believe that any definition of a Reliability Directive should require that within the communication it should be stated that "This is a Reliability Directive." to avoid any possibility of confusion.
Response: The definition does not include the regulated action. Requirement R1 handles the action. Compliance is measured against requirements, not definitions. The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. This comment will be passed to that team for consideration. No change made.		
Ameren	No	R2. When is “shall inform” to occur; timely, promptly, ... It would be injurious to BES reliability for the TOP to get such information, say 15 minutes or half-hour later as many other things are likely to be put in place on the assumption the directive is “ok”. R3. The wording is incorrect it implies the TOP will notify the RC and its

Organization	Yes or No	Question 1 Comment
		TOP's. The word other may be missing. But even with other the question it begs which other TOP's? It could be argued that the RC only needs to know Emergencies that are both actual and anticipated. They would want to know about them whether they are actual or anticipated. This direction here is not clear; it may be helpful to use two sentences to address and clarify the issues of this requirement. R4. What is meant by emergency assistance is not clear; clarify and provide examples. Is it emergency energy? Is it emergency food? Is it emergency crews? This ambiguity is a compliance nightmare as you have to prove you have everything covered that could loosely be interpreted as emergency assistance. If the SDT has an idea what they are expecting, it should be listed. If they don't have an idea of what constitutes emergency assistance, then we recommend removing it from the Requirement. R5. The Requirement should be re-written to say "Each TOP shall inform only if it adversely affects others its RC and other TOP's (Which other TOP's? This direction here is not clear; clarify) of its operations known or expected to result in an Adverse Reliability Impact ..." R6. What is meant by negatively impacting is not clear; clarify and provide examples. For example, using the words as listed, economic impact might be a consideration. The Standard should not be setting up a condition where TOPs tell GO/GOPs that they might suffer economic harm as a result of one of the communication channels being down. As currently worded this might lead to a civil issue instead of a BES reliability issue. R8. There are SOLs that are developed in real-time (as evidenced by the multi-time-horizon assigned). It might be possible for such an SOL to develop and have to be resolved for local area reliability only, before the RC could be notified. This Requirement should insert the word planned before SOL. Alternatively, insert where time permits in place of real-time.

Organization	Yes or No	Question 1 Comment
		R9. What is meant by continuous duration is not clear; clarify. Is it 5 minutes, 15 minutes, an hour, a day? Anything more than 5 minutes is likely to be in the thermal time-constant period where rating could be affected. We feel that the real intent of this requirement is that TOPs resolve SOLs. It is not so much how long, as it is that they are not purposely delaying the resolution. The Requirement should be re-written to say "The TOP's will resolve as soon as possible anys SOL...... with no intentional time delay..." R10. The Requirement as written should be prefaced with "when time permits, each Transmission Operator....." The idea of time permitting is alluded to in R5, "unless conditions do not permit such communications".

Response: R2: The Reliability Directive in question will include the timeframe for the response if one is needed. No change made.

R3: The word 'other' is not required. The language following Transmission Operator confines the set of which Transmission Operators. No change made.

R4: The NERC defined term "Emergency" was not the intent of this requirement. In this requirement, 'emergency' means actions taken quickly in response to an immediate need. No change made.

R5: The requirement has the Transmission Operator with the issue limited to notifying those "other Transmission Operators" whose Transmission Operator Areas are expected to have an Adverse Reliability Impact. No change made.

R6: NERC requirements are concerned only with reliability of the BES, not economic harm. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made.

R8: The key phrase in this requirement is 'based on its assessment'. No change made.

R9: Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. 'Continuous duration' has its common meaning. No change made.

Organization	Yes or No	Question 1 Comment
R10: Requirement R5 allows for the possibility of a suddenly developing condition. Requirement R10 is concerned with the reporting of actions after they occur. No change made.		
Tacoma Public Utilities	Affirmative	We would like to request that specific definitions are included for the individual time horizons. We suggest the following potential definitions: 1. Same Day Operations - Routine actions required within the time frame of a day, but not real-time. 2. Real-time Operations - Actions required within one hour or less to preserve the reliability of the bulk electric system. 3. Operations Assessment - Follow-up evaluations and reporting of real-time operations.
Response: These are defined in the NERC SDT Guidelines. No change made.		
NIPSCO	Yes	In R8 consider changing "internal area" to "Transmission Operator Area" In R9 consider clarifying "continuous duration", what is that?
Response: The SDT replaced 'internal area reliability' with 'reliability internal to its Transmission Operator Area'. It is possible that a Transmission Operator Area has no SOLs that fit this requirement. However, extensive comments received throughout the life of this project indicate the need for such an inclusion. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. Ratings include the element of time, that is, ratings are two dimensional, magnitude and time exceeded. 'Continuous duration' has its common meaning. No change made.		
Georgia System Operations	Yes	GSOC agrees in general but feels that some clarity should be provided. The purpose of the language "each SOL which, while not IROLs, have been identified by the Transmission Operator as supporting its internal area

Organization	Yes or No	Question 1 Comment
		reliability based on its assessment of its Operational Planning Analysis" (OPA) is not clear. Is the intent to clarify the meaning of SOL? If so the definition in the glossary should be updated to clarify the meaning and the clarification should be removed whenever used in TOP-001, 002, or 003. Is the intent to limit which SOLs are being referred to? Not each SOL but each SOL which have been identified as supporting the internal area reliability based on the assessment of its OPA. Could this language be deleted and still convey what is required?
Response: The SDT disagrees that the phrase is not clear. It is identifying SOLs that the Transmission Operator feels are important enough to request that they be monitored similar to an IROL. This could occur for any number of reasons. No change made.		
Associated Electric Cooperative, Inc.	Yes	R3 Guidance Add: A Guidance Section for Requirement R3 clarifying “anticipated Emergency” - AECI believes the SDT should draft guidelines as to what “anticipated Emergency” means within this requirement. That guidance should also caution against dumping information (data-overload) upon neighboring parties, for trivial impacts to their system. Rationale: In earnest to avoid non-compliance with R3, entities could blast their neighbors with all changes, regardless of impact, and then the purpose of this requirement will be lost.) R6 Requirement wording Change: “negatively impacted” To: “known negatively impacted” Rationale: While 1st hand affected parties are likely known, secondarily affected parties might pose a compliance problem. R8 Guidance Add: An R8 Guidance section Rationale: AECI’s understanding is that our providing our RC with AECI’s most-limited-element equipment seasonal operating limits and short-term limits, where applicable, meets this requirement. If we are wrong, then additional guidance is definitely necessary.
Response: The requirement is limited by the fact that actions are based on your assessment of the Operational Planning		

Organization	Yes or No	Question 1 Comment
Assessment. No change made. The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. If a data point provided by a Balancing Authority to its Reliability Coordinator is missing due to a telemetry outage between the Balancing Authority and Reliability Coordinator, the Balancing Authority must notify the Reliability Coordinator. However, other entities that subsequently receive that point from the Reliability Coordinator as part of a larger data stream are not involved in the telemetry outage and would not be notified by the Balancing Authority. No change made. The Transmission Operator must comply with FAC standards for proper definition of SOLs. An SDT cannot give compliance advice.		
Dairyland Power Cooperative	Yes	Concern re R5. The determination of when an operating condition could be "expected to result in an Adverse Reliability Impact" would be difficult and ambiguous.
Response: The Transmission Operator is in the best position to know if other areas may suffer an Adverse Reliability Impact. The examples cited in the requirement: "Such operations may include relay or equipment failures and changes in generation, Transmission, or Load" are intended to give guidance. No change made.		
NV Energy	Yes	Yes, however, there are a few points to note: Part A, Section 1 continues to title this standard as "Coordination of Transmission Operations, while the header of the Standard was changed to simply "Transmission Operations". The requirements R6 and R8 appear to be outside the realm of real-time operations, R6 dealing with planned outages of telemetry, comm, and control equip, and R8 dealing with communication of SOL's or other limits. It is confusing to mix in Operations Planning type requirements in a standard that otherwise deals with real-time grid operations. Suggest relocating these two to the Operations Planning Standard, TOP-002-3.
Response: Title: Conforming change has been made. R6 and R8: Telemetry outages may be planned for the same day or in the next hour. SOLs may be affected in similar timeframes (new topology forcing a readjustment of the system, for instance). No change made.		

Organization	Yes or No	Question 1 Comment
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	From the GO/GOP perspective, Ingleside Cogeneration LP believes that the SDT has captured the appropriate circumstances for when a Reliability Directive is issued and identified - and the circumstances under which it may be not be possible to accommodate one.
US Bureau of Reclamation	Yes	
Westar Energy	Yes	
FirstEnergy	Yes	
Dominion	Yes	
PacifiCorp	Yes	
Western Area Power Administration	Yes	
FMPP	Yes	
Luminant Energy Company, LLC	Yes	
Independent Electricity System Operator	Yes	
Response: Thank you for your support.		

2. **The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: There were four common concerns expressed in the comments.

First, the "rationale box" for Requirement R1 was eliminated. The SDT agreed that the rationale offered was inappropriately addressing more of a compliance issue than explaining the background reasoning.

Second, commenters questioned the use of Facility Ratings and Stability Limits in Requirement R1 rather than the use of the terms Interconnection Reliability Operating Limit and System Operating Limit. The SDT prepared responses to clarify the reasoning for the use of Facility Ratings and Stability Limits, but did not change the wording of the requirement.

Third, the commenters questioned the use of the phrase "internal area reliability" in Requirement R2. The SDT revised Requirement R2 to change the phrase from "internal area reliability" to "reliability internal to its Transmission Operator Area" to clarify that the requirement is related to a Transmission Operator Area, which is a defined term, and that it is a reliability concern within that area, not one that concerns other areas nor does it rise to the level of adversely affecting the reliability of a wider area ~~or~~ of the Bulk Electric System.

Fourth, some commenters expressed concern about Requirement R3 and the notifications of entities which are identified as having roles in operating plans developed by the Transmission Operator in Requirement R2. The concern was related to whether the notifications may conflict with confidentiality requirements. The SDT explained that the notifications are simply to alert the entities that they have been identified as having roles in the operating plans to address reliability issues, but that such notifications do not have to include specifics about what the plan is to address. The entity may know that it may be called upon to perform its role of switching, changing of generator output, or other similar actions, but no specific information would be issued that may result in the unintended consequence of giving any entity "market power" or other competitive advantage.

The SDT has made no substantive changes to the requirements of TOP-002-3. However, Requirement R2 was clarified as follows:

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

Organization	Yes or No	Question 2 Comment
Muscatine Power & Water	Negative	First and foremost is the Requirement in TOP-002-3 for having a process for performing an "Operational Planning Analysis." That term, "Operational Planning Analysis," does not have a FERC-approved definition. The definition floating around at NERC implies some sort of simulation (with or without a tool) being perform next-day to determine exceedence of facility ratings or stability limits.
Response: The definition of Operational Planning Analysis was approved by FERC in March 2011.		
New Brunswick Power Transmission Corporation	Negative	R3: The TOP may not have authority over external registered entities. The TOP should only have to notify and coordinate with those external entities that have the necessary authority.
Response: Requirement R3 deals with operations planning, thus the notification would be to convey information—not an instruction to implement. The hierarchy of authority is known by the Transmission Operator and other registered entities. This is known even if they are members of differing market structures, contract arrangements, or other organizational arrangements; thus the Transmission Operator will know the effective path of communications to use. No change made.		
ISO/RTO Standards Review Committee	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase ‘within its TOP Area or for which it has been notified by another TOP under R3’ in R1 immediately following (IROL).
Pepco Holdings Inc	No	PHI supports the comments provided by the ISO/RTO Standards Review Committee.
ISO New England Inc.	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity.

Organization	Yes or No	Question 2 Comment
		Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Constellation Energy	No	CCG, CECD and CPG concur with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
BGE	No	BGE concurs with ISO/RTO Standards Review Committee Position: Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1 immediately following (IROL).
Southwest Power Pool Reliability Standards Development Team	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase 'within its TOP Area or for which it has been notified by another TOP under R3' in R1

Organization	Yes or No	Question 2 Comment
		immediately following (IROL).
Southwest Power Pool, Inc.	Negative	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. Requiring the TOP to develop a plan to operate within each IROL in R1 is too broad. To narrow the scope of this requirement we suggest inserting the phrase ‘within its TOP Area or for which it has been notified by another TOP under R3’ in R1 immediately following (IROL).
Nebraska Public Power District	No	Even though the SDT directs us to the SOL methodology in the FAC standards which specify N-1 contingencies, R1 is not as clear in specifying N-1 contingencies as the old R6 was. We would prefer to maintain that clarity. We suggest the following language for R1: “Each Transmission Operator shall have an Operational Planning Analysis assessing whether the planned Transmission Operator Area operations for the next day will exceed the area Facility Ratings or Stability Limits during anticipated normal and Contingency (at a minimum N-1 Contingency planning) event conditions.” Requiring the TOP to develop a plan to operate within each IROL in R2 is too broad. To narrow the scope of this requirement we suggest inserting the phrase ‘within its Transmission Operator Area or for which it has been notified by another TOP under R3’ in R1 immediately following (IROL).
Response: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to		

Organization	Yes or No	Question 2 Comment
analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies1identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made. Requirement R2 is the correct reference for the second group of comments, not Requirement R1. The SDT believes it is important for the Transmission Operator to develop a plan to operate within each IROL. Further the Reliability Coordinator must inform the Transmission Operator of all IROLs that impact its Transmission Operator Area or that its area can impact in other areas; and other Transmission Operators must inform them of SOLs that either impact its area or that its area may impact. Similar to the often-discussed "loop flow" concern, each entity must recognize that operations within its area may impact SOLs in another area and vice		

Organization	Yes or No	Question 2 Comment
versa.		
United Illuminating Company	No	The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, UI suggests the requirement should either state the requirement for a process to conduct an Operational planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement.R1. The Transmission operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. R2: uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-011 R5. SOL's that affect a TOP internal area would also affect the RC area.
Northeast Power Coordinating Council	No	The phrasing of the Requirement R1 does not match the rationale box. Based on the Rationale R1, suggest that the requirement should either state the requirement for a process to conduct an Operational Planning Analysis for the next day, or shall conduct an Operational Planning Analysis for the next day. It seems the team could phrase this as a Risk Based Requirement.R1. The Transmission Operator shall CONDUCT an Operational Planning Analysis for the next day's planned operations within its Transmission Operator Area to identify where Facility Ratings or Stability Limits will be exceeded during anticipated normal and Contingency event conditions. Requirement R2 uses a phrase each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 that implies an SOL exists in the TOP area that was not identified pursuant to FAC-011 R2 and communicated per FAC-014 R5. SOL's that affect a TOP

Organization	Yes or No	Question 2 Comment
		internal area would also affect the RC area. The Drafting Team needs to define the term "internal area reliability" in order to improve the clarity of the standard (see Question 1 comments regarding TOP-001 Requirement R8). Regarding Requirement R3, would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall?
Response: R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate and, thus, still applies. R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. R3: When providing the notification, no confidential information must be provided, only that the entity has a role to play in an operating plan that the Transmission Operator has developed to address system constraints. No other regulations may be violated in the issuance of the notifications, but the Generator Owner, Generator Operator, or Balancing Authority would know that they would be asked to change something in their generation operations as a part of their role(s).		
Southwest Power Pool Regional Entity	No	See item number 5 for comments.
Response: See the response to Q5.		
Bonneville Power Administration	No	Given the potential uncertainty regarding how many day ahead studies may be required, BPA suggests adding more clarity to the standard TOP-002-3. BPA recognizes that various regions experience peak operations at different times of the day, anticipated generation patterns shift over the course of the day, and

Organization	Yes or No	Question 2 Comment
		transmission facilities come in and out of service for planned work at various times throughout the day. Hence, due to these multiple shifts in forecast system conditions, it is unclear whether more than one study is required to meet the requirements of this standard.
Response: The requirement states "what" must be done, not "how" it is to be done. There are many tools (please note that use of tools is not required) and the various processes and/or tools may differ with a resulting different number of "studies" required. The Operational Planning Analysis is to address "expected system conditions", such as load forecasts, generator outputs, and system constraints. For those larger, more complex systems, the SDT expects the process may be complex. However, for smaller entities which may have a very constant load characteristic and a very robust transmission system, one analysis may suffice for a very broad range of different "expected system conditions". No change made.		
Imperial Irrigation District (IID)	No	R1 - This requirement requires the Transmission Operator to have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions (Comment) - Recommendation that the requirement language be changed to "Each TOP shall perform the required Operational Planning Analysis for Next-Day Operations to assess if the Next-Day Operations Plan will exceed any of its Facility and/or stability limits under normal or emergency conditions". R2 - This requirement requires the Transmission Operator to develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 (Comment) Recommend that the language be revised for clarity to state the following; "The TOP shall develop a plan to operate within established IROL and SOLs according to the Operation Planning Analysis performed for its Next-Day Operation in Requirement 1. R3 - This requirement requires the TOP to notify all NERC registered entities

Organization	Yes or No	Question 2 Comment
		identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) (Comment) - Recommend revising the language in the requirement to state the following; "The TOP shall notify all affected NERC Registered entities of possible impacts identified in its Operational Planning Analysis for its Next-Day Operations in Requirement 1. M2 - The measurement requires the TOP to have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement (Comment) - Revise the Measurement to state the following; "The TOP shall have evidence that it developed a plan to operate within established IROL or SOLs supporting its internal reliability area as a result of its Operational Planning Analysis performed". M3 - Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records. (Comment) - Revise the measurement to sate the following; "The TOP shall provide evidence that it notified affected NERC Registered Entities as being impacted in the Operational Planning Analysis related to its Next-Day plan. Such evidence shall include but not be limited to dated E-Mails, Operator Logs, or Voice Recordings. Data Retention - Each Transmission Operator shall keep data or evidence to show compliance for each Requirement and Measure for a rolling six month period for analyses, the most recent three months for voice recordings, and 12 months for operating logs and e-mail records unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer. The Compliance Enforcement Authority shall

Organization	Yes or No	Question 2 Comment
		keep the last audit records and all requested and submitted subsequent audit records. (Comment): The time frames appear to be pretty specific for the data retention. However when will the entity know that it has to save the evidence farther back than the set time frame. Would it not be better to have the Data Retention language require the entity to save all evidence back 12 months and to save any evidence related to a system disturbance/event?
Response: R1: The requirement is to assess the Operational Planning Analysis (OPA). An entity may do this by performing a new OPA each day, or even more often, but it is not required to do so. The SDT can postulate that the varying results of the assessment(s) may indicate the need for a new analysis, or may indicate that the existing analysis is still appropriate. No change made. R2: See above response for R1. No change made. R3: The SDT requirement to notify entities of their role(s) in the operating plans goes beyond just informing them of system impacts. The role(s) will notify the entity that they will have actions to take when the Transmission Operator must implement an operating plan to address system constraint(s). No change made. The SDT made no changes to Measures M2 and M3 because the requirements were not changed. Data Retention: The language indicates that the entity will be asked by its Compliance Enforcement Authority (or directed) to save the evidence father back than the set timeframe. No change made.		
Kansas City Power & Light	No	The words "develop a plan" in R2 are too broad. Recommend the requirement be modified to include, "within its TOP area" as in R1. Also the use of "Contingency event conditions" is not clear in requirement R1. Recommend specifying n-1 as the contingency scope.
Response: The SDT believes it is important for the Transmission Operator to develop a plan to operate within each IROL. Further the Reliability Coordinator must inform the Transmission Operator of all IROLs that impact its Transmission Operator Area or that its area can impact in other areas; and other Transmission Operators must inform them of SOLs that either impact its area or that its area may impact. Similar to the often-discussed "loop flow" concern, each entity must recognize that operations within its area may impact SOLs in another area and vice versa. No change made.		

Organization	Yes or No	Question 2 Comment
The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will		

Organization	Yes or No	Question 2 Comment
allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.		
SERC OC Standards Review Group	No	Why did the Drafting Team use the terms “Facility Ratings” and “Stability Limits” in Requirement 1 rather than SOLs and IROLs as used in subsequent Requirements? We suggest the Drafting Team further clarify or define the term “supporting internal area reliability” as an aid in demonstrating compliance and how this requirement (R2) enhances reliability.
Response: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: “R2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate		

Organization	Yes or No	Question 2 Comment
transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made. R2: The SDT has revised the language. This requirement enhances reliability by clarifying that a Transmission Operator may identify certain SOLs as important, although they don't rise to the level of an IROL, but support reliability internal to the Transmission Operator Area. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
US Army Corps of Engineers	No	Issue: The SDT uses a non FERC approved term of Operational Planning Analysis, This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval. Issue: R2: statement its internal area reliability Should be clarified to state: R2: Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its

Organization	Yes or No	Question 2 Comment
		Transmission Operators area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: statement its internal area reliability could be clarified to state: has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis
MRO-NSRF	No	Issue: The SDT uses a non FERC approved term of "Operational Planning Analysis", This term is in the NERC Glossary of terms. Recommend that this statement be forwarded with this Standard to FERC for approval. Issue: R2: statement "...its internal area reliability..." Should be clarified to state: R2: Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: statement "...its internal area reliability..." could be clarified to state:"...has been identified by the Transmission Operator as supporting its Transmission Operators area, identified as a result of the Operational Planning Analysis..."
Response: The definition of Operational Planning Analysis was approved by FERC in March 2011. R2: The SDT has revised the language to change "internal area reliability". **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. M2: The SDT revised Measure M2 to correspond to the changes in Requirement R2.		
ACES Power Marketing	No	We largely agree with the changes but have identified the following specific

Organization	Yes or No	Question 2 Comment
Member Standards Collaborators		issues.We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted into the purpose statement. For Requirement R1, it is not clear why focus is on Facility Ratings and Stability Limits rather than SOLs. We suggest using the term SOL instead.
Southwest Transmission Cooperative, Inc.	Affirmative	We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted into the purpose statement. For Requirement R1, it is not clear why focus is on Facility Ratings and Stability Limits rather than SOLs. We suggest using the term SOL instead.

Response: The SDT has been given SDT Guidelines that state that all requirements are written for the BES. No change made.

R1: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by

Organization	Yes or No	Question 2 Comment
the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies1identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.		

Organization	Yes or No	Question 2 Comment
Georgia System Operations	No	GSOC feels that some clarity should be provided. In R1, the rationale confuses things. It states things that are not in the requirement and goes beyond the requirement. If something is intended by the language of R1 other what is stated, then that intent should be clearer in the requirement. For example if a process is required, then state so in the requiremnt. It should not be in a rationale. Also, the comment in the rationale about being able to complete the analysis even if tools are not available is inappropriate in this standard since the situation is covered in EOP-008-1. Remove the rationale and if needed clarify the requirement. R1 states that the TOP should be allowed to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. It does not state that an assessment of this must be done, only that it be allowed.R2 states that the TOP shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which has been identified by the TOP as supporting its internal area reliability, identified as a result of the OPA performed in Requirement R1. R1 does not require that IROLs and SOLs be identified. What if the TOP does not identify if there are any SOLs as a result of the OPA? There are other examples in these standards in which something in the OPA is referred to but is not required to be in the analysis. Better clarity is needed regarding just what the end results of the analysis must be. R3 requires that entities identified in the plan be notified as to their role. Would this be initially and whenever their role changes thereafter? Or just once? Data Retention: It states that if a TOP is found non-compliant, it shall keep information related to the non-compliance until found compliant. It is inappropriate to use the phrase "found compliant." NERC and the REs do not find entities compliant.
Response: R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate		

Organization	Yes or No	Question 2 Comment
and, thus, still applies. No change made. R1: The requirement is for the Transmission Operator to have an Operational Planning Analysis (timeframe of an OPA is built into the definition). If the Transmission Operator chooses to use an existing OPA, then it cannot be confirmed to be appropriate for the next day without performing an assessment of the OPA. If the Transmission Operator chooses to build a new OPA (each day or at a differing recurrent schedule), then the assessment is part of building the OPA in order to make it appropriate to the "expected system conditions". No change made. Identification of SOLs: There is no need to state in these requirements that the IROLs and SOLs be identified, because the Transmission Operator is required to do that by the FAC standards. The end result of an OPA is an evaluation of the "expected system conditions" and the development of operating plans that may be needed to address any identified system constraints. No change made. R3: Entities are to be notified as to their role every time it performs the assessment. Data Retention: The language you question has been provided to the SDT by the NERC Compliance group and is "boiler plate" language that the SDTs are instructed to use. No change made.		
City Water Light and Power (CWLP) - Springfeild - IL	No	R1 should utilize SOL and IROL criteria as opposed to Facility Ratings and Stability Limits criteria for consistency and clarity R1 Rationale language lacks clarity. Poor definition of "process", "tools", and "procedures" could be construed to indicate that a TO must be able to perform analysis internally even when basic non-automated "tools" such as offline power flow software are not available. The intent of "tool" is unclear in general for this instance. If the intent is to capture the use of online automated tools such a Real-Time Contingency Analysis and ensure that offline analysis capabilities are retained, the language should explicitly include "online automated tools" or "real-time automated tools"
Response: The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented		

Organization	Yes or No	Question 2 Comment
within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.). Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities. FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made. R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to		

Organization	Yes or No	Question 2 Comment
assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate and, thus, still applies. No change made.		
We Energies	No	How current should the Operational Planning Analysis be? By definition it can be 12 months ahead. Data Retention: The second paragraph states that Measures must be complied with. Compliance with measures cannot be required.
Response: The Transmission Operator must have an OPA (the timeframe is contained within the definition). Data Retention: You are correct. The SDT has made a conforming change to the language to eliminate the phrase.		
American Transmission Company, LLC	No	Requirement 1 - Granted, if the rationale does not mandate "how" an analysis is completed, a better requirement of the "what" should be stated. If this analysis base-case, N-1, is unilateral by the TOP, without iteration with the BA, then should the process be documented?
Response: R1 rationale box: The SDT agrees and has eliminated the rationale box. Requirement R1 requires the Transmission Operator to assess its Operational Planning Analysis each day for the next day to determine whether the analysis is still appropriate and, thus, still applies. No change made. In the development of the planned operations for the next day, the Balancing Authority would supply expected generator outputs to the Transmission Operator. The Transmission Operator would determine whether there are any system constraints that would require changes by the Balancing Authority, such as a re-dispatch or other action that may require alterations to the expected generator outputs to be performed by the Balancing Authority. If such things are identified, the Transmission Operator will notify the entities of their role(s) in the operating plans.		
Consolidated Edison Co. of NY, Inc.	No	Comments: In Requirement R2 the Drafting Team needs to define the term "internal area reliability" in order to improve the clarity of the standard. Regarding Requirement R3: Would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888

Organization	Yes or No	Question 2 Comment
		Firewall? Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.
Orange and Rockland Utilities, Inc.	No	Regarding Requirement R3: Would notifying GO's of "their roles" in the IROL/SOL mitigation plan provide them market power or represent a violation of Order 888 Firewall? Requirement 3 should be deleted. Market rules may prohibit the TOP from notifying all identified registered entities of their involvement in a given Operational Planning Analysis. This notification function may need to be performed by the RC.
Response: R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. R3: When providing the notification, no confidential information must be provided, only that the entity has a role to play in an operating plan that the Transmission Operator has developed to address system constraints. No other regulations may be violated in the issuance of the notifications, but the Generator Operator, Generator Operator, or Balancing Authority would know that they would be asked to change something in their generation operations as a part of their role(s). The Transmission Operator may direct Balancing Authorities for reliability reasons. Yes, the Reliability Coordinator may also direct the Balancing Authorities, but the Transmission Operator is not precluded from doing so. No change made.		
Manitoba Hydro	No	R1 - Given that an Operational Planning Analysis is itself an assessment of planned operations (i.e. the definition of Operational Planning Analysis is 'An analysis of the expected system conditions for the next day's operation…') it is unnecessary to state that the Operational Planning Analysis must allow an assessment of planned operations. Accordingly, Manitoba Hydro suggests that the phrase that will allow it

Organization	Yes or No	Question 2 Comment
		to assess…' be replaced with "assessing".
Response: The SDT believes your comments represent a question of semantics. The SDT differentiates between an "analysis" and an "assessment". The difference is that the entity assesses the analysis it has performed to determine that the OPA is still representative of "expected system conditions". That is "what" must be done. The "how" is left up to the entity. The SDT can postulate that the entity may perform a new OPA and, in the process, assess that it is representative of "expected system conditions", or that it may take an existing OPA and assess it to determine that it still is representative. No change made.		
ReliabilityFirst	No	ReliabilityFirst has the following comments for consideration:1. R1 - ReliabilityFirst recommends removing the rationale box from the standard. ReliabilityFirst believes this is not really the rationale for the requirement but rather explains how to measure (show evidence) for the requirement.2. R2 - ReliabilityFirst recommends deleting the following words from the requirement, "which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1". ReliabilityFirst believes this language does not add anything to the requirement. 3. R2 and R3 - R3 requires the Transmission Operator to notify all NERC registered entities identified in the plan(s) but there is no corresponding requirement for the Transmission Operator to identify NERC registered entities in their plans. ReliabilityFirst recommends incorporating this concept into R2. 4. Data retention - ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example, the last sentence states "the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>paragraphs in the Data Retention section.</td></tr>
<tr><td colspan="3">Response: R1 rationale box: The SDT agrees and has eliminated the rationale box.

R2: A Transmission Operator may identify certain SOLs as important, although they don’t rise to the level of an IROL, but support reliability internal to the Transmission Operator Area. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations. However, the SDT has clarified the wording in Requirement R2 due to comments received.

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

The SDT believes that to notify the entities, the Transmission Operator must somehow know who the entities are and that stating a requirement to identify them before notifying them would be redundant and would not add to reliability. No change made.

Data Retention: The entity is to do all the shorter retention requirements first and go to the longer retention only if the CEA asks them to do so. No change made.</td></tr>
<tr><td>Duke Energy</td><td>No</td><td>o R2 - Consistent with our comment above on TOP-001-2 Requirement R8, the phrase “supporting its internal area reliability” should be further clarified in some way.

o M2 typo - the word “plan” has an extra “n”.</td></tr>
<tr><td colspan="3">Response: R2: The SDT has revised the language.

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

M2: The typo has been corrected. Please note that the typo is not seen in the “clean” copy.</td></tr>
</table>

Organization	Yes or No	Question 2 Comment
South Carolina Electric and Gas	No	Please provide clarity on the phrase "support its internal area reliability" in R2.
Response: R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Oklahoma Gas and Electric	No	Regarding R2, please consider additional clarifying language that each TOP need only develop a plan to operate within IROL and SOL that is applicable to them. Also, clarify what "internal area realibility" means - is this the same as Transmission Operator Area discussed in R1?
Response: The SDT believes it is important for the Transmission Operator to develop a plan to operate within each IROL. Further the Reliability Coordinator must inform the Transmission Operator of all IROLs that impact its Transmission Operator Area or that its area can impact in other areas; and other Transmission Operators must inform them of SOLs that either impact its area or that its area may impact. Similar to the often-discussed “loop flow” concern, each entity must recognize that operations within its area may impact SOLs in another area and vice versa. No change made. R2: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Westar Energy	No	The stated rationale for R1 raises more concerns than the actual language in R1. How can an entity complete an analysis by procedure? The rationale seems to indicate that an Operational Planning Analysis is possible

Organization	Yes or No	Question 2 Comment
		without tools, please explain. Are anticipated contingency event conditions intended to be N-1 from the planned system configuration?

Response: R1 rationale box: The SDT agrees and has eliminated the rationale box.

The requirement states "what" must be done, not "how" it is to be done. There are many tools (please note that use of tools is not required) and the various processes and/or tools may differ with a resulting different number of "studies" required. The Operational Planning Analysis is to address "expected system conditions", such as load forecasts, generator outputs, and system constraints. For those larger, more complex systems, the SDT expects the process may be complex. However, for smaller entities which may have a very constant load characteristic and a very robust transmission system, one analysis may suffice for a very broad range of different "expected system conditions".

The SDT points the commenter to the Glossary definitions of Facility Rating, Stability Limit, Operational Planning Analysis (OPA), Transmission Operator Area, Interconnection Reliability Operating Limit (IROL), and System Operating Limit (SOL) for reference (not included here for brevity). The SDT chose this language for proposed TOP-002-3, Requirement R1 because the OPA encompasses many reliability concepts. The OPA presents a predicted system status for the system conditions that are represented within and by the OPA, including things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).

Some commenters suggested that the SDT should use IROLs and SOLs in the requirement rather than Facility Ratings and Stability Limits. The SDT chose not to do so because the IROLs and SOLs represent only part of what the OPA is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them.

FAC-008 and -009 require facility owners to have a methodology for determining Facility Ratings for their facilities and to communicate those ratings to operating entities that have a need for those ratings. FAC-011 requires Reliability Coordinators to have a methodology for determining SOLs (and the subset of SOLs which rise to the level of IROLs) for the operations horizon and those methodologies are to respect the Facility Ratings they have been given by the facility owners. Further, FAC-014 requires the Reliability Coordinator, Planning Coordinator, Transmission Planner, and Transmission Operator to communicate those limits to the operating entities which need them in system operations activities.

Organization	Yes or No	Question 2 Comment
FAC-011, for the operations horizon, requires that the SOLs represent the following: "R2.2 Following the single Contingencies1identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur. R2.2.1. Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system." TOP-002-3, as proposed, relates to the Operations Planning time horizon. When the Facility Ratings and Stability Limits are in place as required by the FAC standards, TOP-002-3, Requirement R1 requires the Transmission Operator (TOP) to have an OPA that will allow the TOP to assess whether any Facility Ratings or Stability Limits have been exceeded for the expected system conditions represented by the OPA. The SDT chose not to repeat the requirements of the FAC standards in the drafting of the TOP standards. No change made.		
Ameren	No	R1. The current language invites a retrospective assessment and a potential compliance issue that if a bad event occurs that was not in the forecast, it may call into question whether the TOP adequately "allowed it to assess" whether operations where within limits. We recommend SDT re-write the requirement: "Each TOP shall have an Operational Planning Analysis that represents projected System conditions for the next day, within its Transmission Operator Area, to identify any projected exceedance of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions." R2. Although the time-horizon assignment provides some cover for real-time SOLs, it would be preferable to add direct clarification to the Requirement as follows. "Each TOP shall develop a next day plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) ..." R3. Taken literally, this Requirement could require TOP notification to a GOP/PSE/LSE that they will be dispatched down in real-time for a projected congestion issue (SOL).

Organization	Yes or No	Question 2 Comment
		This does not make sense and certainly not in organized LMP markets where they would have advance knowledge of market conditions AND FOR THINGS THAT ARE ROUTINE. This is the nexus of the problem for us with this Requirement. The need to notify others of their roles should be restricted to unusual actions in the case of SOL resolution. Arguably this could be true for IROLs too but given the impact perhaps it could remain. We suggest that the Requirement say, "Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) when those actions are unusual or abnormal actions." OR"Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s) for the resolution of IROLs or when those actions are unusual or abnormal actions for the resolution of SOLs."
Response: The SDT believes the existing language of draft Requirement R1 says what you are requesting. No change made. R2: The FAC standards provide clarity as to the development of Facility Ratings and SOLs. IROLs are a sub-set of SOLs. To provide differing language here would be to provide potential conflict and confusion. No change made. R3: Requirement R3 deals with operations planning; thus the notification would be to convey information—not an instruction to implement. The hierarchy of authority is known by the Transmission Operator and other registered entities. This is known even if they are members of differing market structures, contract arrangements, or other organizational arrangements; thus the Transmission Operator will know the effective path of communications to use.		
Roger C Zaklukiewicz		Requirement R1 needs to be modified as the following terms in 1.1 are problematic to compliance and enforcement. Remove the term "but not limited to". Why must the data to be exchanged include that on all facilities that operate at levels lower than the Bulk Electric System to ensure the reliability of the interconnected BES - especially if the BES is to be recognized as the "bright line" transmission system that operates at 100 kV or above.
Response: The SDT believes you intended these comments for TOP-003, Requirement R1. Please see the responses to TOP-003 comments.		

Organization	Yes or No	Question 2 Comment
California ISO	Affirmative	The ISO supports the changes made in TOP-002-3 but notes that the "Seasonal Assessment" previously required by TOP-002-2 is no longer addressed in the TOP-002-3 wording. Is this an oversight or is this seasonal assessment going to be contained elsewhere?
Response: The SDT places reliability emphasis upon a daily assessment for the next day (hence the Operational Planning Analysis). The entity could have a library of various OPAs from which to select an appropriate one for assessment, or could develop an OPA each day (or even more often), but is not required to do so.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	The term "anticipated ... Contingency event conditions" in R1 is not a NERC defined term and could be interpreted as requiring analysis of all contingencies including extreme events. The requirement should clarify if it only applies to certain types such as category P1 or whether each TO can independently select which types of contingencies they anticipate. One suggested form or rewording the requirement could be: R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal conditions and TPL-001-2 category P1 Single contingencies.
Response: The Operational Planning Analysis (OPA) is a defined term and includes "expected system conditions" for the next day. The Contingencies which would apply are presented in the TPL standards. The Transmission Operator must address, at a minimum, the Contingencies presented, but may address more than what is required. Further, Facility Ratings and Stability Limits are defined terms and the FAC standards present the level of Contingencies that must be addressed in the Facility Ratings and SOLs methodologies. To specify only the proposed P1 single Contingencies may be too limiting. No change made.		
Tennessee Valley Authority	Affirmative	Further clarification is needed on the phrase - "internal area reliability".
Progress Energy	Yes	A definition of "internal area reliability" is needed

Organization	Yes or No	Question 2 Comment
Response: The SDT has revised the language. **R2.** Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.		
Associated Electric Cooperative, Inc.	Yes	R1 Rationale Change: Rework or remove entirely Rationale: The R1 Rationale section does not match the R1 requirement as currently worded, and frankly is impossible, within the timing constraints of next-day analysis. (Example: PSS/E is technically a tool for steady-state network analysis. Without that tool, or a similar network-analysis tool being available, such analysis would be impossible by hand.) R3 Requirement wording Change: "in the plan(s)" To: "in the N-1 contingency-related plan(s)"Then Append: ", N-2 related contingency-plan(s) should be omitted unless highly plausible." Rationale: This recommended change seeks to avoid information overload on neighbors, while still encouraging more in-depth near-term contingency planning.
Response: R1 rationale box: The SDT has eliminated the rationale box. Requirement R3 deals with operations planning; thus the notification would be to convey information—not an instruction to implement. The hierarchy of authority is known by the Transmission Operator and other registered entities. This is known even if they are members of differing market structures, contract arrangements, or other organizational arrangements; thus the Transmission Operator will know the effective path of communications to use. The plans are limited to those developed in Requirement R2. No change made.		
Independent Electricity System Operator	Yes	We assess that the industry's comment on R3 regarding the need to inform all NERC registered entities identified in the plan(s) was due to the absence of a requirement to identify these entities. We therefore suggest to revise Requirement R2 to drive home the need to identify registered entities that are included in the plan(s) to operate to within IROL and SOL, and set the stage for R3:Each Transmission Operator

Organization	Yes or No	Question 2 Comment
		shall develop a plan, and identify the entities that will be required to implement actions, to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
Response: The SDT believes the current wording of Requirement R3 is sufficient. No change made.		
American Electric Power	Yes	R2: Once again, it needs to be clarified whether this requirement is in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumes this is based on Real Time Flow, however we encourage the drafting team to provide clarifying language to make it more clear to the reader.
Response: TOP-002-3 is about Operations Planning, thus it cannot be addressing actual Real-time flow. It addresses those flows contained in the Operational Planning Analysis (OPA) and the assessment thereof. Based upon that assessment and the OPA, the Transmission Operator will develop a plan to operate. No change made.		
NIPSCO	Yes	None at this time
Dairyland Power Cooperative	Yes	
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	
Omaha Publc Power District	Yes	
Texas Reliability Entity	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 2 Comment
US Bureau of Reclamation	Yes	
Xcel Energy	Yes	
FirstEnergy	Yes	
Dominion	Yes	
PacifiCorp	Yes	
Lincoln Electric System (LES)	Yes	
LG&E and KU Serivces	Yes	
Western Area Power Administration	Yes	
FMPP	Yes	
Luminant Energy Company, LLC	Yes	
Response: Thank you for your support.		

3. **The SDT made changes to TOP-003-1 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: There were a number of requests for clarification which the SDT have addressed either through changes to the language of the requirements or through specific responses to those comments. There was one substantive change to the standard – the addition of the Distribution Provider to the list of applicable entities in general and to Requirement R5 specifically.

The SDT changed the effective date for all requirements in proposed TOP-001-2, TOP-002-3, and TOP-003-2 to 12 months in response to comments except for proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.

The following changes have been made due to industry comments:

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. The specification shall include:

R3. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.

R4. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification as developed in Requirement R1to entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R2. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R~~4~~5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

Data Retention 4. Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~and operating analysis assessment processes and tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R4 and Measurement M4.

Organization	Yes or No	Question 3 Comment
Luminant Energy	Abstain	TOP-003-2 as currently written does not provide any recourse for the entity receiving a data request if that entity feels the data request is unreasonable either in content or timing or if the entity does not have the data available to submit. As such I would recommend modify R5 as follows: R5. Each......shall satisfy the obligations of the documented specification for data. R5.1. If the entity receiving the data request cannot provide the requested data either in content or timing then the entity receiving the data request shall notify the requesting entity and provide a reason for not providing the data.
Kansas City Power & Light	No	These requirements do not recognize the limitations of data exchange capability with an entity and the sources of data an entity has. Recommend these requirements be modified to include "within the data exchange capabilities and data available of the recipient of the data specification".
City Water Light and Power (CWLP) - Springfeild - IL	No	R1 and R2 require specifications for data exchange which do not account for the ability of the respondent to meet the specification. As written, the requirement could force a respondent to continue to provide data with such a format, periodicity,

Organization	Yes or No	Question 3 Comment
		or deadline that would be an undue burden to the respondent. All requirements should explicitly stress a mutually agreed plan and R1.1/R2.1 should refer to classes or types of as a qualifier. Likewise, R5 should explicitly state that respondents shall satisfy the obligations within the context of a mutually agreed specification.
Dairyland Power Cooperative	No	R1 and R2 refer to "A periodicity for providing data" and "The deadline by which the respondent is to provide the indicated data". What if this specification is unreasonable? To address this concern, DPC suggests adding the words "mutually agreeable" as was used in reference to the format specification.
Response: Requirement R1 should prevent a Transmission Operator from requesting data that another entity can't provide. There are arbitration processes available to straighten these matters out if all else fails. No change made.		
Muscatine Power & Water, MidAmerican Energy Co.	Negative	There is a great possibility of double jeopardy when R3 and R4 have in part the statement of "...in meeting its NERC-mandatory reliability requirements." So, an Entity could be found non-compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown "...in meeting its NERC-mandatory reliability requirements," then they would be found non-compliant with this Standard. It is not clear why this Standard is being written with the statement of "...in meeting its NERC-mandatory reliability requirements."
US Army Corp of Engineers	No	Issue: There is a great possibility of double jeopardy when R3 and R4 have in part the statement of in meeting its NERC-mandatory reliability requirements. So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown in meeting its NERC-mandatory reliability requirements then they would be found non compliant with this Standard. It is not clear why this Standard is being written with the statement of: in meeting its NERC-mandatory reliability requirements. As stated in the NERC Standard Process Manual, under Background, NERC works with all stakeholder segments of the electric industry, including electricity users, to develop standards for the reliability planning and

Organization	Yes or No	Question 3 Comment
		reliable operation of the bulk power systems. Recommend that in meeting its NERC-mandatory reliability requirements, be deleted and replaced with reliable operation as defined as operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance. Or, please review IRO-010-1a, requirement 1 and use like terminology for this Standard.
Lincoln Electric System (LES)	No	Please refer to comments submitted by MRO's NERC Standards Review Forum for LES' concerns related to TOP-003.
MRO-NSRF	No	Issue: There is a great possibility of "double jeopardy" when R3 and R4 have in part the statement of "...in meeting its NERC-mandatory reliability requirements." So, an Entity could be found non compliant with R1 or R2 and also not fulfill R3 or R4. Or if an entity was found non compliant with any of the unknown "...in meeting its NERC-mandatory reliability requirements" then they would be found non compliant with this Standard. It is not clear why this Standard is being written with the statement of: "...in meeting its NERC-mandatory reliability requirements". As stated in the NERC Standard Process Manual, under Background, "NERC works with all stakeholder segments of the electric industry, including electricity users, to develop standards for the reliability planning and reliable operation of the bulk power systems. Recommend that "...in meeting its NERC-mandatory reliability requirements", be deleted and replaced with "reliable operation" as defined as "...operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance...". Or, please review IRO-010-1a, requirement 1 and use like terminology for this Standard.
Response: The SDT views the requirements as two separate and distinct actions. In Requirements R1 and R2, the entity is developing the specification and in Requirements R3 and R4 the entity is distributing the specification. Therefore, there is no double jeopardy.		

Organization	Yes or No	Question 3 Comment
No change made. This standard exactly matches IRO-010-1a in content and intent. No change made.		
Volkmann Consulting, Inc.	Negative	TOP-003-2 R5 does not adequately replace PRC-001 R2. TOP-003-2 R5 does not require notifying the RC and drops the requirement of GOP to analyze equipment and relay failures, TOP-003-2 R5 states GOP obligations as specified in R3 and R4, however R3 and R4 are not applicable to GOP.
Response: There is nothing in PRC-001-1, Requirement R2 about analysis. The SDT believes you are thinking of PRC-004-2a, Requirement R2 which is not part of this project and is not intended to be replaced by the revised standards. No change made.		
Northeast Power Coordinating Council	No	TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates the TO, LSE, and Generator Owners to provide this real-time data. These entities provide a wealth of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It is not clear that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.TOP-003 R5 has only a severe VSL. Data providers can provide hundreds if not thousands of points to TOPs. If one RTU goes down is the data provider going to be assessed a severe VSL? TOP-003-2 R1.1 states: R1. Each Transmission Operator and Balancing Authority shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: [Violation Risk Factor: Low] [Time Horizon: Operations Planning] 1.1. A list of required data to be exchanged including, but not limited to: Long term outages of Bulk Electric System (BES) Facilities. Operating parameters for BES Facilities and Facilities at voltage levels lower than the BES NPCC believes language such as but not limited to and levels lower than the BES to be problematic and beyond the scope of what is needed in the standard and also creates potential for compliance issues.
United Illuminating Company	No	TOP-003 R1 and R2 require data specifications for real-time monitoring. R5 obligates TO, LSE, and Generator Owners to provide this real-time data. These entities provide a multitude of SCADA data that is utilized in real-time monitoring by TOPs and BAs. It

Organization	Yes or No	Question 3 Comment
		is not clear to UI that a communication error or data quality error for several contiguous time periods or intermittent quality issues would not trigger a violation. This could become an overwhelming compliance issue.
Response: It is not the intent of the SDT that TOP-003-2 penalizes entities for communication errors. The intent is to have the data communications established. Communication errors are handled in the COM standards. No change made.		
Dominion	No	If this question was meant to refer to TOP-003-2, then Dominion offers the following comments: M5 reads "Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, and Transmission Owner receiving a data specification in Requirement R2 or R3 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R4. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities." Since R2 was added, Dominion suggest M5 should read as "receiving a data specification in Requirement R3 or R4 shall make available evidence that is has satisfied the obligations of the documented specifications for data in accordance with Requirement R5....".
Response: The SDT agrees and has changed measure M5 accordingly. **M5.** Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R~~4~~5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.		
SERC OC Standards Review Group	No	There appears to be ambiguity for R1 and R2 - is the VSL applicable to the TOP/BA requesting the data or is it applicable to the TOP/BA providing the data? If it applies to the TOP/BA requesting the data we would suggest that the SDT be consistent with

Organization	Yes or No	Question 3 Comment
		the VSLs in IRO-10-1a.
Response: The SDT does not see the confusion pertaining to Balancing Authority/Transmission Operator that the VSLs in Requirements R1 and R2 apply. The requirement is for the Transmission Operator/Balancing Authority to document a specification, it would have to be the Transmission Operator/Balancing Authority writing the specification and ultimately requesting the data through Requirements R3 and R4. No change made.		
Constellation Energy	No	The Drafting Team may want to consider addressing a time period for responding to a data request to ensure parties are given time to respond. For example, a BAs data request may be driven by the TOP's data request. If a BA receives a data request for information from the TOP that sources from a GOP, the BA will need to establish a data request from the GOP that has the same deadline. If the GOP is unable to supply the data they may be non-compliant if they do not meet the deadline.
Response: Parts 1.4 and 2.4 discusses a deadline for responding to the data request. No change made.		
ACES Power Marketing Member Standards Collaborators	No	We largely agree with the changes but have identified the following specific issues.We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Because of the difficulties experienced by some entities in receiving the RC data specification in IRO-010-1a, we recommend that the implementation of TOP-003-2 Requirement R5 occur a couple of months after the implementation in TOP-003-2 Requirements R1-R4. IRO-010-1a is a parallel standard to TOP-003-2 and the effective date of the distribution of the RC data specification was simultaneous to

Organization	Yes or No	Question 3 Comment
		the effective date of the requirement for the recipients to comply with the data specification. This meant that the RC could provide the data specification on the same date that the recipients had to meet the data specification. Unfortunately, there were some entities expecting to receive the data specification that did not and were concerned about a potential non-compliance. What if an auditor determined the RC should have provided the data specification? Would the entity that expected to receive the data specification be held responsible? By staggering the effective date of Requirement R5, this confusion can be avoided.
Southwest Transmission Cooperative, Inc.	Affirmative	We believe that purpose statement should clearly state that the standard is limited to the Bulk Electric System (BES). NERC compliance staff has interpreted standards as applying to the Bulk Power System (BPS) if they are not specifically limited to the BES. More specifically in response to comments that CAN-0016 impermissibly extended the standard to the BPS, NERC responded that Section 39 of the EPAct of 2005 requires standards to apply to the BPS unless the standard restricts itself. Because the BPS can be interpreted to be broader than the BES and there is no need for the standard to apply broader than the BES, we would like to see BES inserted back into the purpose statement. Because of the difficulties experienced by some entities in receiving the RC data specification in IRO-010-1a, we recommend that the implementation of TOP-003-2 Requirement R5 occur a couple of months after the implementation in TOP-003-2 Requirements R1-R4. IRO-010-1a is a parallel standard to TOP-003-2 and the effective date of the distribution of the RC data specification was simultaneous to the effective date of the requirement for the recipients to comply with the data specification. This meant that the RC could provide the data specification on the same date that the recipients had to meet the data specification. Unfortunately, there were some entities expecting to receive the data specification that did not and were concerned about a potential non-compliance. What if an auditor determined the RC should have provided the data specification? Would the entity that expected to receive the data specification be held responsible? By staggering the effective

Organization	Yes or No	Question 3 Comment
		date of Requirement R5, this confusion can be avoided.
Response: The purpose of the standard is to address reliability needs. Any concerns about BES vs. BPS in standards are better directed toward the NERC Standards Committee. No change made. The SDT has changed the effective date for the implementation of this project to 12 months except for proposed TOP-003-2, Requirements R1 and R2 which will be in 10 months.		
LG&E and KU Serivces	No	LG&E and KU Services do not believe that data/evidence retention requirements should be modified by the Compliance Enforcement Authority. This potentially will result in different data retention requirements across regions. A Compliance Enforcement Authority should enforce only what is written within the standard and not have the option of expanding the requirement. 4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.
Response: The SDT is using standard boilerplate language in the Data Retention section. It is not within the scope of the SDT to alter such language. Questions about such situations should be taken to the NERC Standards Committee. No change made.		
Georgia System Operations	No	R5 is too unilateral. A TOP could send a spec to an entity for some data that the entity is not able to provide and per this requirement the entity will still be required to provide it. There must be some mutual agreement to more than just the format. There must be agreement to what can be provided and that the data is needed by the TOP's operating analysis assessment processes and reliability monitoring tools used in meeting its NERC-mandated reliability requirements. Also some provision must be allowed to cover when data or the transfer method is unavailable (e.g., when an RTU goes down). A similar situation applies to BAs sending a spec to an entity.
Response: Requirement R1 should prevent a Transmission Operator from requesting data that another entity can't provide. If all else		

Organization	Yes or No	Question 3 Comment
fails, there are arbitration processes to clear up such matters. No change made.		
Western Area Power Administration	No	Data an entity specifies in requirement documents need to have some kind of reasonability limit or explanation as to what the data will be used for. As written a TOP or BA can request anything they want and other entities will be required to provide that data, even if the requested data is not available as requested. An entity can also request data not pertinent to the reliability of their system and other entities will still be required to provide it. An entity required to provide the data should have an opportunity to challenge the need for data requested. At least one BA in WECC is running a market and data provided will be used in their market, not for reliability.
Response: Requirement R1 clearly states that the data requested must be for use in an entities Real-time monitoring function or for its Operational Planning Analysis. This restricts the data to reliability oriented data. No change made.		
We Energies	No	R1.4 and R2.4: The deadline must allow time to gather and send the data. If the TOP said immediately, you would be immediately non-compliant. In addition, R2 should include data necessary to perform at least Next Day analysis, even Operational planning Analysis. R5 needs to include the DP. Data Retention: Each bullet states that monitoring is required in accordance with Measures. Measures cannot be requirements.
Response: The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. There are arbitration processes available if all else fails. No change made. Balancing Authorities do not perform Operational Planning Analyses as this is a transmission-oriented task. However, the SDT has inserted a phrase to cover analyses. **R2**. Each Balancing Authority shall create a documented specification for the data necessary for it to perform analysis functions and its required Real-time monitoring. The specification shall include:		

Organization	Yes or No	Question 3 Comment
The SDT agrees. **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. The inclusion of requirements and measures in data retention is standard language and simply ties the data retention language to the requirements and measures together. It does not imply that the measures are requirements. No change made.		
American Transmission Company, LLC	No	In the introduction to this question, the Standard number should be corrected to TOP-003-2. Requirement 1- A data specification must have bounds. There is nothing that would preclude a request for data that is not achievable yet is mandated to be satisfied by Requirement 5. Requirement 1, sub-Requirement 1.2 may never be arrived at given the former.
Response: The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. There are arbitration processes available to straighten these matters out if all else fails. No change made.		
Omaha Publc Power District	No	OPPD is requesting clarification on operational data requirements (R1 and R3) related to "documented specification for the data necessary for it to perform..." What the document should include that is specifying operational data request from or to other Transmission Operators. Additionally, how often operational data specification document should be provided/updated to or from other Transmission Operators.
Response: The SDT believes it is clear as to what is required – the data needed to perform the entities Real-time monitoring and Operational Planning Analyses. No change made. Requirement R1, Part 1.3 covers the periodicity issue. No change made.		
Manitoba Hydro	No	M1 – This measure goes beyond the requirements of the standard, as there is no

Organization	Yes or No	Question 3 Comment
		requirement for a specification document to be dated. Manitoba Hydro suggests either striking 'dated' from M1 or adding the requirement to have a 'dated documented specification' to R1. M2 – Same comment as M1. Manitoba Hydro suggests either striking 'dated' from M2 or adding the requirement to have a 'dated documented specification' to R2. A R3 - For consistency with R1 and overall clarity, Manitoba Hydro suggests changing the wording of R3 to 'Each Transmission Operator shall distribute its documented specification developed in accordance with R1 to those entities that have data required by the Transmission Operator to support its Operational Planning Analysis and Real-time monitoring '. The VSL for R3 should be changed accordingly as well. R4 - For consistency with R2 and overall clarity, Manitoba Hydro suggests changing the wording of R4 to 'Each Balancing Authority shall distribute its documented specification developed in accordance with R2 to those entities that have data required by the Balancing Authority to perform its Real-time monitoring'. The VSL for R4 should be changed accordingly as well.
Response: M1/M2: The requirements refer to deadlines which imply a timing element so it is permissible to add 'dated' to the measures as adherence to a deadline doesn't make much sense otherwise. No change made. R3/4: The SDT does not feel the suggested change adds further clarification. No change made.		
E.ON Climate & Renewables	No	ECRNA appreciates the efforts of the drafting team in eliminating duplicative requirements and efforts, as this is an important part of developing clear and concise standards. However, we are concerned about the end result of an unbounded data specification. Although requirements R1 through R4 are directed toward the Balancing Authority and Transmission Operator, these requirements have a direct impact on the other applicable entities. The lack of guidance to and expectations of the data and format could and most likely will lead to a wide range of data specifications from the multitude of Balancing Authorities and Transmission

Organization	Yes or No	Question 3 Comment
		Operators in North America. Entities that own or operate facilities in multiple regions and work with many BAs and TOPs may have difficulty responding to each individual specification's needs, including timeframe, and format. Also considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable. In addition, the sub-requirements to R1 and R2 could be written more clearly to identify who the TOPs and BAs are expected to mutually agree with and request information from. One can assume the applicable entities listed in the standard, but explicitly stating this within the standard is a better method and ensures entities are provided an opportunity to provide input in the data specification format.
Response: The data specification concept provides entities with flexibility in crafting the specifications to the exact data that it needs to perform its tasks. Data specifications may be different for the same type of entity within a Transmission Operator Area let alone in different regions of the country. Guidance is provided within the requirement on format, etc. No change made. The severity factor on Requirement R5 is based on its level of importance and its relationship to a similar requirement in IRO-010-1a which has been approved by FERC. No change made. The SDT sees no reliability value in duplicating a list within the bounds of the requirement itself. No change made.		
Texas Reliability Entity	No	Regarding R1, we are concerned that the proposed requirement gives each TOP too much latitude to determine what data it considers necessary. This may cause confusion due to significant differences in data specified by different TOPs and the ability of TOPs to unilaterally change their data specifications. We would prefer that the standard include a basic list of data to be included in the specification. The reference to "mutually agreeable format" in R1 part 1.2 is problematic because it allows the respondents to interfere in the TOP's data collection process. The TOP should be allowed to dictate a reasonable format for data submission. In R2, we are opposed the removal of "Operational Planning Analyses" (OPA) for a Balancing Authority in this requirement, because the BA is "the responsible entity that

Organization	Yes or No	Question 3 Comment
		integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real-time." A BA should create a documented specification for the data necessary for it to perform an OPA just as a TOP does. The reference to "mutually agreeable format" in R2 part 2.2 is problematic because it allows the respondents to interfere in the BA's data collection process. The BA should be allowed to dictate a reasonable format for data submission. In R3 we suggest changing "operating analysis" to "Operational Planning Analysis," which is a more precise term for what appears to be intended. The same change should be made in Measure M3. In R4 we suggest adding "Operational Planning Analysis," to be consistent with our comment that R2 should require "Operational Planning Analysis" data in the BA's data specification. In the Measures, please check and correct the references to Requirement numbers - some references are to the wrong requirements. Under Data Retention, in the 4th bullet starting with "Each Balancing Authority...", the phrase "and operating analysis assessment processes and" should be struck because it does not align with requirement R4 as currently written. However, we support adding "Operating Planning Analysis" in R4, and this data retention reference should be consistent with the requirement.
Response: The requirement is designed to give the Transmission Operator the flexibility it needs to get the data it requires. It is bound by the provision for data needed to support its Real-time monitoring and Operational Planning Analyses. It is absolutely true that different Transmission Operators may be specifying different data due to their differing operational requirements. Supplying a basic list of data does not provide this flexibility and does not ensure that all data needed would be in the list. No change made. It is unreasonable to allow a Transmission Operator or any other entity to arbitrarily introduce a format that other entities can't support. There has to be some degree of mutual agreement to decisions of this type in order to be fair to all parties involved. The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of		

Organization	Yes or No	Question 3 Comment
reliability. There are arbitration processes available to straighten these matters out if all else fails. No change made. A Balancing Authority can't perform an Operational Planning Analysis by definition since this defined term only applies to transmission-oriented analysis. However, the SDT has added wording to cover analyses. **R2**. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. The specification shall include: R3 – The SDT agrees and has made the language consistent. R3. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. The SDT has changed Requirement R4 to be consistent with the revised Requirement R2. **R4**. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. The references in the Measures have been corrected. The SDT agrees and has made the suggested change consistent with the responses concerning requirement R2 above. **Data Retention 4**. Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~and operating analysis assessment processes and tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R4 and Measurement M4.		
Indiana Municipal Power Agency	No	IMPA believes that the entities (Transmission Operator and Balancing Authority) should be required to create a documented specification that lists exactly what the entities (in R5) need to provide to them to meet the requirement and not be allowed to say that "it is in our manuals and/or agreements." When the Transmission Operator and/or Balancing Authority only references their manuals, it is up to the entity (in R5) to read the manuals that are referenced and then try to come up with a documented specification listing on their own which may or may not include

Organization	Yes or No	Question 3 Comment
		everything that is required by the TO or BA which makes the current draft standard's language very ambiguous. IMPA is not objecting to these entities using manuals as long as a specific documented specification is created and distributed that does more than just list the name of manuals. The documented specifications need to be detailed in what is required from entities to aid in preventing possible non-compliance issues due to an entity missing an item in a manual or including unnecessary items due to being left to their own interpretations.
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by Indiana Municipal Power Agency concerning the need for clearer communication of data specifications in R3 and R4 in order to facilitate compliance with R5.
Response: The intent of Requirements R1 and R2 is for the entity's to do exactly what is cited in your comment. The entity must spell out each piece of data it requires and specify it to the affected entity who will be supplying the data. No change made.		
US Bureau of Reclamation	No	The language change in R1 has not been incorporated into the sub requirements. The requirement R1 was modified to eliminate the second party. A mutual agreement is required in R 1.2 but only party is listed in R1. The language should specify that the TOP is to coordinate its data requests with the appropriate entities and seek mutal agreement on the format.
Response: The SDT believes it is clear who must agree to the format and sees no additional clarity being provided by listing the entities in the text of the requirement. No change made.		
Xcel Energy	No	Applicability - why are Distribution Providers not subject to this standard? Is it possible that a TOP or BA may need information form a DP to perform an "OPA"? "Mutually agreeable" in 1.2 should be removed. The TOP and BA should work with the subject entities, however stating that something must be mutually agreed upon could create delivery and acceptance of data in a less than desired form solely to meet the words of the requirement.

Organization	Yes or No	Question 3 Comment
Response: The SDT agrees and has added the Distribution Provider to the applicable entities and to Requirement R5. **R5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. There are arbitration processes available to straighten these matters out if all else fails. No change made.		
ReliabilityFirst	No	ReliabilityFirst has the following comments for consideration:1. R1 and R2 - ReliabilityFirst recommends changing the phrase “shall create...” to “shall have...” in R1 and R2. 2. R1 and R2 - ReliabilityFirst recommends changing Part 1.2 and Part 2.2 to state “A format”. ReliabilityFirst believes it may be difficult to audit and enforce the phrase “mutually agreeable”. 3. R3 - ReliabilityFirst seeks clarification on the term “operating analysis assessment” used in R3. Is this language referring to the Transmission Operators Operational Planning Analyses as required in R1? If not, can the SDT clarify what the phase “operating analysis assessment” is referring to? 4. R3 and R4 - ReliabilityFirst seeks clarity on what the phrase “NERC-mandated reliability requirements” is referring to? Is it referring to FERC approved NERC standard requirements or does it encompass NERC Directives, CANs, NERC bulletins, etc. as well? 5. R3 and R4 - R3 references “those entities” and R4 just references “entities”. ReliabilityFirst recommends modifying either R3 or R4 to use consistent language. 6. Data retention - ReliabilityFirst believes the first paragraph of the Data Retention section is in conflict with the additional paragraphs of the Data Retention section. For example the last sentence states “the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full

Organization	Yes or No	Question 3 Comment
		time period since the last audit" as a catch all. Regardless of the other shorter data retention periods located in the subsequent paragraphs, the entity still needs to retain the evidence for the full time period since the last audit. ReliabilityFirst recommends only keeping the first paragraph and deleting the subsequent paragraphs in the Data Retention section.
Response: The SDT does not believe that the suggested change provides any additional clarity. No change made. The SDT has crafted this standard with the belief that two reasonable parties will be dealing with each other in the overall best interest of reliability. The suggested change does not clarify the situation further than what is already written. There are arbitration processes available to straighten these matters out if all else fails. No change made. The SDT has changed requirement R3 for clarity. R3. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. The phrase is in reference to approved Reliability Standards. The SDT agrees and has changed Requirement R3 accordingly. The SDT is utilizing NERC supplied boilerplate language in the Data Retention section. It is out of the scope of this project to make changes to that language. No change made.		
Nebraska Public Power District	No	Comments: Requirements R1 & R2 do not put any meaningful bounds on the data that a TOP or BA may request in the name of monitoring real-time operations. There is no check or balance on spcifying timeframes when the data is required either. Attachment 1 TOP-005-1 contained the type of data that may be required and as such provided a fremework for what type of data was required for real-time monitoring of the Bulk Electric System. As written, it would be possible for a BA or TOP to request data that a registered entity does not have available and require it in an unrealistic timeframe. This puts those entities in a position where they cannot comply with the standard, even though the data requested may not be important in

Organization	Yes or No	Question 3 Comment
		the monitoring of the Bulk Electric System. There need to be reasonable limits on the information requested and how quickly new information may be required from other registered entities.
Response: Requirements R1 and R2 are bound by the language restricting the specifications to Real-time monitoring or Operational Planning Analysis. This restricts the data requested to be only for reliability-related purposes. No change made.		
Ameren	No	R1. Each TOP shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. The specification shall include: 1.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the TOP. This is illogical and needs to be clarified or removed. 1.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R2. Each BA shall create a documented specification for the data necessary for it to perform its required Real-time monitoring. The specification shall include: 2.2. What is meant by mutually agreeable is not clear it implies more than one party, yet this Requirement only applies to one party the BA. This is illogical and needs to be clarified or removed. 2.4. Strike the deadline and consider using time frame or duration by which the respondent is to provide the indicated data. R3. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert “from R1” There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they

Organization	Yes or No	Question 3 Comment
		should be spelled out explicitly here and likely in R1 as well. R4. After the first instance of specification; state from which requirement; if you were intending R1, then for clarity insert "from R1" There is potentially another compliance issue present; what is meant by NERC-mandated reliability requirements is not clear nor does not match the wording in R1. If the meaning/intent is that NERC-mandated reliability requirements is in fact Operational Planning Analysis and Real-time monitoring, then use those words. If the SDT has other things that the data specification is to be distributed for, then they should be spelled out explicitly here and likely in R1 as well. R5. We recommend re-writing: "Each TOP, BA, GO, GOP, IA, LSE, and TO receiving a data specification in Requirement R3 or R4 shall provide the data associated with said data specification. "

Response: R1.2/R2.2**:** The SDT believes that the context is clear and that duplicating a list of entities in the language of the requirement does not provide any additional clarity. No change made.

R1.4/R2.4:The SDT believes that there is no additional clarity provided in the suggested language. No change made.

R3/R4: The SDT does not see any additional clarity provided by the suggestion. No change made.

R3/R4: The term refers to the approved reliability standards. No change made. The SDT has changed the requirements for consistency of wording.

> **R3**. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.
>
> **R4**. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.

R5: The SDT sees no additional clarity being provided by the suggested change. No change made.

Organization	Yes or No	Question 3 Comment
GTC	No	M4 is misreferencing R2 and R4 and should be corrected as follows: ....”receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R5.”
Response: The SDT believes that you meant Measure M5. The references have been corrected. **M5**. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, ~~and~~ Transmission Owner, and Distribution Provider receiving a data specification in Requirement R~~2~~3 or R~~3~~4 shall make available evidence that it has satisfied the obligations of the documented specifications for data in accordance with Requirement R~~4~~5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.		
Intellibind	No	There is no assurance that in R1 and R2 that the format designated by the BA or TOP is Mutually Agreed by the parties. It will be essentially impossible for auditors to destinguish what is directed vs. what has been negotiated.
Response: There is no need to distinguish between the two cases. The only one that is pertinent is what the two parties have agreed upon. No change made.		
Progress Energy	Yes	Please include "operational Planning Analyses" in R2 as you have in R1.
California ISO	Affirmative	The words “and Operational Planning Analyses” should be added to the end of the first sentence in R2 (the Operational Planning Analysis is included in R1). A similar addition should be made to R4.
Response: By definition, the Balancing Authority can’t perform an Operational Planning Analysis as it is a transmission-oriented task. However, the SDT has added wording to cover analyses. **R2**. Each Balancing Authority shall create a documented specification for the data necessary for it to perform analysis functions and its required Real-time monitoring. The specification shall include:		

Organization	Yes or No	Question 3 Comment
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	If a Transmission Operator or a Balancing Authority is requesting data from another entity, they must demonstrate a reliability impact validating the need for the requested data.
Response: Demonstrating the need would be an onerous task with no reliability benefit. The Transmission Operator and Balancing Authority are constrained as to what they can request by the language in the requirements. They can only ask for what is needed to support their assigned tasks. No change made.		
City of Tallahassee	Affirmative	While it specifies that the examples are only possibilities for evidence, the inclusion of “with acknowledgement” to “web postings” in M2 & M3 for TOP-003-2 will become onerous. It requires another entity to respond in order to have evidence we were compliant.
Response: The SDT believes you meant Measures M3 and M4 but agrees and has changed the measures accordingly. **M3**. Each Transmission Operator shall make available evidence that it has distributed its data specification as developed in Requirement R1to entities that have data required by the Transmission Operator’s ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R2. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records. **M4**. Each Balancing Authority shall make available evidence that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority’s analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include but is not limited to web postings ~~with acknowledgement~~ with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.		
NIPSCO	Yes	In R3 & R4 the phrase "in meeting its NERC-mandated reliability requirements" is too open-ended and may be difficult to comply with. This should be more specific; what requirements are these.

Organization	Yes or No	Question 3 Comment
Response: The phrase encompasses the approved reliability standards. No change made.		
Associated Electric Cooperative, Inc.	Yes	TOP-003-1 R1, R2, and R3 Guidelines Add: Guidelines Section - These requirements are all written as highly TOP-centric and BA-centric, without regard to the confusion and work-load a single published plan could cause small entities. If hundreds or perhaps thousands of data-points are cited within a uniformly circulated plan, yet some entities provide only one or two obscure points within that plan, then the TOP or BA is being unnecessarily inconsiderate, and should have appropriately filtered that request for their audience. Rationale: Very large TOPs or BAs would benefit from being reminded that they need to consider their audience when sending out plans as data-requests to small entities. There is no need to overwhelm smaller entities with a lot of unrelated data, or data that does not seem to match their own identifiers. We can do better.
Response: The SDT understands the smaller entities perspective. Each entity will be provided a data specification that is unique to them with only the data that they can provide included. No change made.		
Independent Electricity System Operator	Yes	We agree with the addition of R2, but have a concern over Measure M2, which says:M2: Each Balancing Authority shall make available its dated, current, in force documented specification for data in accordance with Requirement R2.The wording “dated, current, in force” does not reflect what’s in the requirement R2, and is not necessary. This wording pertains to the data retention requirement, which is already included in the second bullet in Section D, 1.3 - Data Retention:”Each Balancing Authority shall retain their dated, current, in force, documented specification for the data necessary for them to perform their required Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.”We suggest to remove this wording from M2.
Response: The requirement refers to deadlines which imply a timing element so it is permissible to add ‘dated’ to the measures as adherence to a deadline doesn’t make much sense otherwise. No change made.		

Organization	Yes or No	Question 3 Comment
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	Although we would prefer to see a consolidated RC-BA-TOP data specification, Ingleside Cogeneration LP agrees that TOP-003-1 is a good first step in that direction. Any help the SDT can provide to reduce overlap in data requests and to drive to a common format is appreciated.
Response: The requirement is designed to give the Transmission Operator/Balancing Authority the flexibility it needs to get the data it requires. It is bound by the provision for data needed to support its Real-time monitoring and Operational Planning Analyses. It is absolutely true that different Transmission Operators/Balancing Authorities may be specifying different data in different formats due to their differing operational requirements.		
Duke Energy	Yes	o R1.1 - Consistent with our Question #1 comment above on using the actual wording of the BOT-approved definition of “Adverse Reliability Impact” since it has not yet been approved by FERC, “Operational Planning Analysis” has likewise not yet been approved by FERC as of the latest version of the Glossary posted on the NERC website, December 13th, 2011. Suggest using the wording of the defined term. If the SDT decides to instead keep the defined term, “Analyses” should be “Analysis”. o R3 - Current wording is awkward. Suggest rewording as follows: “Each Transmission Operator shall distribute its data specification to entities that have data required for operating analysis assessment processes and reliability monitoring tools used by the Transmission Operator in meeting its NERC-mandated reliability requirements.” o R4 - Current wording is awkward. Suggest rewording as follows: “Each Balancing Authority shall distribute its data specification to entities that have data required for reliability monitoring tools used by the Balancing Authority in meeting its NERC-mandated reliability requirements.” o Measures and Data Retention - change to align with suggested R3 and R4 rewording above.
Response: Adverse Reliability Impact and Operational Planning Analysis are FERC approved terms. Adverse Reliability Impact was		

Organization	Yes or No	Question 3 Comment
approved on March 16, 2007 and Operational Planning Analysis was approved on March 17, 2011. The Transmission Operator could be running more than one Operational Planning Analysis thus the use of the plural term. No change made. The SDT does not see any additional clarity from the suggested change. However, the SDT has changed Requirements R3 and R4 due to other comments. Measures and Data Retention have been updated accordingly. **R3**. Each Transmission Operator shall distribute its data specification as developed in Requirement R1to ~~those~~ entities that have data required by the Transmission Operator's ~~operating analysis assessment processes~~ Operational Planning Analysis and ~~reliability~~ Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements. **R4**. Each Balancing Authority shall distribute its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and ~~reliability~~Real-time monitoring ~~tools~~process used in meeting its NERC-mandated reliability requirements.		
American Electric Power	Yes	R5: It should be noted that some of the information that could potentially be requested may already be available, for example on reliability coordinator systems. AEP suggests that the requirement be modified so that it does not unintentionally create an edict to provide "any data" to parties simply because R5 could be interpreted as allowing requests of any kind. The possibility of a dispute resolution process managed by the reliability coordinator(s) might also address these possible scenarios. Such a process should address, at a minimum, specifics such as timing, format and general logistics concerning the requested data. AEP does not currently have any text to suggest in this regard, but asks the SDT to consider such a change.
Response: Requirement R5 is bound by the constraints of Requirements R1 and R2 so that not just any information can be requested. There are arbitration processes available to resolve disputes. No change made.		
Bonneville Power Administration	Yes	BPA is in support of standard TOP-003-1, due to the importance of being able to receive data.
ISO/RTO Standards Review Committee	Yes	

Organization	Yes or No	Question 3 Comment
FirstEnergy	Yes	
Imperial Irrigation District (IID)	Yes	
Southwest Power Pool Reliability Standards Development Team	Yes	
PacifiCorp	Yes	
Southwest Power Pool Regional Entity	Yes	
FMPP	Yes	
South Carolina Electric and Gas	Yes	
Oklahoma Gas and Electric	Yes	
Westar Energy	Yes	
Pepco Holdings Inc	Yes	
NV Energy	Yes	
ISO New England Inc.	Yes	
Response: Thank you for your support.		

4. The VRF, VSL, and Time Horizons are part of a non-binding poll. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: Several comments state that the VSLs for TOP-003-2, Requirement R5 were more stringent or severe than the VSLs for the TOP-003-2, Requirements R1-R4. The SDT views Requirements R1-R4 as enabling requirements for making clear what data is required for the responsible entities in Requirement R5 and believe the VSLs align with the stated purpose of the standard to ensure the Transmission Operator and Balancing Authority have the necessary data "to fulfill their operational planning and Real-Time monitoring responsibilities". Several other comments shared the view that the VRFs and VSL for Requirements R1-R4 were not consistent with Requirement R5. The SDT views Requirements R1 – R4 as enabling requirements leading to Requirement R5. The purpose of TOP-003-2 is to make sure the Transmission Operator and Balancing Authority have the data necessary for fulfilling their functional obligations. Thus, the real crux of the standard is to supply data. No changes were made due to these comments.

Changes made due to comments are:

TOP-001-2, Data Retention: Changed retention requirement for voice recordings to 90 calendar days from three calendar months.

TOP-001-2, Requirement R1 VSL: The Severe VSL was reworded for clarity.

TOP-001-2, Requirement R3 Moderate VSL modified by inserting "affected" for consistency with the requirement and other VSLs.

TOP-001-2, Requirement R5 VSLs: A note prior to the VSLs was removed. The note was a vestige from a previous posting explaining how to use the VSLs when both percentages and integers are used in the VSL. Percentages were removed during that past posting and the note should have been removed as well.

TOP-001-2, Requirement R10 VSLs: Changed "has been" to "had been".

TOP-002-3, Requirement R3 Lower and Severe VSLs were modified based on comments and to make them consistent with Moderate and High VSLs. More specifically, the "whichever is less" language was added to the Lower VSL.

TOP-003-2, Requirements R1 and R2 VSLs: Replaced elements with ~~Parts~~ parts to clarify that it is the ~~Parts~~ parts of the requirements that are missed.

TOP-003-2, Requirements R1 and R2, Severe VSL: Changed “four or more” to “four” since there are only four parts.

TOP-003-2, Requirements R3 and R4 VSLs: Added “boiler plate” explanation for how to select if the integer or percentage value is used in selecting the VSL.

No changes were made for the following comments:

TOP-001-2, Requirements R3, R5, and R6 VSLs: A few comments suggested adding percentages to the integer VSLs. The SDT did not believe that probable sample sizes warranted use of percentages.

TOP-001-2, Requirement R5 VSL – Several comments indicated the VSL should be binary and Severe. The SDT disagrees that the VSL ought to be binary. Failure to notify one Transmission Operator of an Adverse Reliability Impact is not as Severe as failing to notify the Reliability Coordinator. Failure to notify the Reliability Coordinator is a Severe VSL. If the Reliability Coordinator knows, then the Reliability Coordinator will ensure the Adverse Reliability Impact is addressed.

TOP-003-2, Requirement R5 VSLs: Several comments indicated concern that the requirement could not be partially satisfied. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc.

Changes made are reflected below:

TOP-001-2, R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, ~~unless~~and such action would have violated safety,

				equipment, regulatory, or statutory requirements.

TOP-001-2, R3	The Transmission Operator did not inform one other Transmission Operator that is known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis

TOP-001-2, R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, ha~~s~~d been exceeded.

TOP-002-3, R3	The Transmission Operator did not notify one NERC registered entity or 5% or less of the NERC registered entities whichever is less identified in the plan(s) cited as to their role in the plan(s).	The Transmission Operator did not notify two NERC registered entities or more than 5% and less than or equal to 10% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify three NERC registered entities or more than 10% and less than or equal to 15% of the NERC registered entities whichever is less, identified in the plan(s) as to their role in the plan(s).	The Transmission Operator did not notify four or more NERC registered entities or more than15% of the NERC registered entities identified in the plan(s) as to their role in the plan(s).

TOP-003-2, R1	The Transmission Operator did not include one of the required ~~elements~~ parts (Part 1.1 through Part 1.4) of the documented	The Transmission Operator did not include two of the required ~~elements~~ parts (Part 1.1 through Part 1.4)-of the documented	The Transmission Operator did not include three of the required ~~elements~~ parts (Part 1.1 through Part 1.4) of the documented	The Transmission Operator did not include four ~~or more~~ of the required ~~elements~~ parts (Part 1.1 through Part 1.4)

	specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.	specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring.	of the documented specification for the data necessary for them to perform their required Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

TOP-003-2, R2	The Balancing Authority did not include one of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its required analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its required analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their required analysis functions and Real-time monitoring.	The Balancing Authority did not include four ~~or more~~ of the required ~~elements~~ parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their required analysis functions and Real-time monitoring.

				OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its required analysis functions and Real-time monitoring.

Organization	Yes or No	Question 4 Comment
Luminant Energy	Abstain	The comments below are in reference to the VSL for TOP-003-2 R5: The VSL for TOP-003-2 R5 places a more stringent severity level on the entities receiving the data requests than it places on the entities that are responsible for creating the data requests. As such, I would suggest changing the VSL for TOP-003-2 R5 to the following: Lower: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy one of the obligations of the documented specification for data. Moderate: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy two of the obligations of the documented specification for data. High: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy three of the obligations of the documented specification for data. Severe: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy four or more of the obligations of the documented specifications for data.
Response: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation should only occur		

Organization	Yes or No	Question 4 Comment
for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. No change made.		
Lincoln Electric System (LES)	No	The word "affected" should be added to the Moderate VSL for TOP-001-2 R3 following "...known or expected to be affected by an actual...".
Response: The SDT agrees and has modified the Moderate VSL. See the redlined VSL in the Summary Consideration for this question to view the changes.		
Duke Energy	No	o TOP-001-2, R8 - Consistent with R3, the Time horizon for R8 should only be Operations Planning. o TOP-001-2 VSLs for R8 and R9 should be changed consistent with our suggested revisions to the requirements. Also see comment below regarding use of percentage ranges. o TOP-002-3 VSLs for R3 - the addition of the percentage range on the Lower VSL makes no sense. The "whichever is less" phrase on the other VSLs could push a violation into a higher VSL because of the percentage range. For example, if the TOP had 10 entities to notify and failed to notify one, then it would be a Moderate violation (10%) instead of Lower. If the TOP had 100 entities to notify and failed to notify four (less than 5%), then it would still be a Severe violation. o TOP-003-2 VSLs for R1 - "Analyses" should be "Analysis", since "Operational Planning Analysis" is a defined term. o TOP-003-2 VSLs for R2 - Severe VSL should just say "four" instead of "four or more" because there are only four required elements. o TOP-003-2 VSLs for R3 and R4 - the addition of the percentage range on the Lower VSL makes no sense. See comment on TOP-002-3 VSLs for R3 above.
Response: TOP-001-2, R8 – The SDT agrees and has modified the Time Horizon for R8 to only cover Operations Planning.		

Organization	Yes or No	Question 4 Comment
TOP-001-2, R8 and R9 – Please see our response to your comments in Q1. TOP-002-3, R3 – The utilization of the "whichever is less" language has been vetted by NERC and is used in other standards. There is an explanatory statement prior to the VSLs for Requirement R3 that details how the VSLs are determined in the examples provided. The SDT did add "whichever is less" in the Lower VSL and "than" in the Severe VSL. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2, R1 – The SDT disagrees. "Analyses" is the plural form of "analysis" and its use is consistent with the requirement. The SDT intended for the data specification to apply to all the analyses that the Transmission Operator must perform and not a single analysis. Otherwise, one could interpret the requirement to require a separate data specification for every analysis performed by the Transmission Operator. Definitions in the NERC Glossary are regularly used in singular or plural form in other standards. No change made. TOP-003-2 R2 – The SDT agrees and has modified the Severe VSL for R2 and R1 as well. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2 VSLs R3 and R4: The utilization of the "whichever is less" language has been vetted by NERC and is used in other standards. The SDT has added an explanatory statement prior to the VSLs for R3 and R4 that explains how the VSL is determined in the examples provided.		
Texas Reliability Entity	No	Regarding the VSL for TOP-001-2 R5, we suggest that it be based on a percent of applicable TOPs rather than number of TOPs, which would accommodate various sized entities. Regarding the VSLs for TOP-001-2 R9 and R11, we recommending adding a time duration reference relating to SOL violations, even if it is not a definite number of minutes. Referring to the VSLs for TOP-003-2 R1, there are only four elements listed, so the reference to "four or more" is nonsensical. Also, there is no difference between omitting four elements and not providing a documented specification at all. Finally, the four listed elements do not appear to have equal importance - perhaps the VSL levels should be assigned based on which elements are missing.
Response: TOP-001-2 R5 – Because VSLs using percentages must use the 5, 10, 15%, etc., scale, the SDT believes using percentages will actually escalate the VSLs for all entities more rapidly and result in a situation where the some levels are never used. In the vast		

Organization	Yes or No	Question 4 Comment
majority of situations, a Transmission Operator will have to notify, at most, its immediate neighboring Transmission Operator-s. A Transmission Operator would have to have more than 26 neighboring Transmission Operator-s before each VSL could be used. The SDT does not believe there will be any Transmission Operator with that many neighboring Transmission Operator-s. No change made. TOP-001-2 R9 & R11 – The timing requirement is implicitly contained within Facility Rating or Stability criteria. No change made. TOP-003-2 R1 – The SDT has changed "four or more" to "four". The SDT understands that failing to meet all four parts may be viewed by some as not providing any data specification. Others may not share that view and may believe that some document could be provided that does not meet any of the requirement parts. Either way the violation will be assessed at a Severe VSL. Additionally, the SDT does not believe missing any one of the four parts will contribute to a greater violation of the requirement than the other parts. See the redlined VSL in the Summary Consideration for this question to view the changes.		
E.ON Climate & Renewables	No	Considering the unknowns in the data specifications, the high severity factor on R5 seems unreasonable.
Kansas City Power & Light	No	The VSL for TOP-003-2, R5 does not recognize partially satisfying a request for data. Recommend the SDT consider a graduated set of severity levels similar to the other requirements in TOP-003-2.
Kansas City Power & Light	Negative	The VSL for TOP-003-2, R5 does not recognize partially satisfying a request for data. Recommend the SDT consider a graduated set of severity levels similar to the other requirements in TOP-003-2.
Response: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation should only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. No change made.		
ReliabilityFirst	No	For the TOP-001-2 standard, ReliabilityFirst disagrees with the VSLs for the following

Organization	Yes or No	Question 4 Comment
		reasons:1. VSLs for R3, R5 and R6 - ReliabilityFirst recommends adding the gradated language of “or X% or less of the entities whichever is less” to the VSLs (this is consistent with the language stated in the TOP-002-3 and TOP-003-2 VSLs). This is needed for smaller Transmission Operators which may have less than four other TOPs to inform. 2. Note in front of VSL 5 - ReliabilityFirst recommends removing the note in front of VSL5 since the note is contrary and is in conflict on how the VSL is set up.
Response: TOP-001-2 R3, R5, and R6: Because VSLs using percentages must use the 5, 10, 15%, etc., scale, the SDT believes using percentages will actually escalate the VSLs for all entities more rapidly and result in a situation where the some levels are never used. In the vast majority of situations, a Transmission Operator will have to notify, at most, its immediate neighboring Transmission Operators and maybe a few additional registered entities. A Transmission Operator would have to notify more than 26 entities before each VSL could be used. The SDT does not believe there will be any Transmission Operator with that many entities to notify. In this case, the SDT believes use of one, two, three, and four represents the best balance between large and small entities. No change made. TOP-001-2 R5 – The SDT has removed the note.		
American Electric Power	No	In general, the VRFs and VSLs are too severe and punitive. Because of this, as well as our objections with the redundancy of requirements in TOP-001-2, AEP cannot support the proposed VRFs and VSLs.
Response: The SDT has not made any changes because of the lack of specificity with the comments.		
Ameren	No	See comments in question 5 regarding VRF.
Response: See response to Q5.		
ACES Power Marketing Member Standards Collaborators	No	The VSLS for TOP-002-3 Requirements R1 and R2 could have more levels based on the number of days for which there is not a plan or Operational Planning Analysis.

Organization	Yes or No	Question 4 Comment
Response: The requirement was written in singular form because the SDT believes it is very important to not miss a single day. Since the requirement is for a single day, FERC VSL criteria will not allow a VSL to accumulate the number of days. No change made.		
ISO/RTO Standards Review Committee	No	TOP-001-2, R3 Moderate VSL - the word “affected’ has been omitted and needs to be inserted. TOP-003-2, R1 & R2 - The use of the term ‘element’ in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 - The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn’t this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
Illinois Municipal Electric Agency	No	Illinois Municipal Electric Agency supports comments submitted by the ISO/RTO Standards Review Committee concerning the need to build some flexibility into the VSL for TOP-003-2 R5.
Pepco Holdings Inc	No	PHI supports the comments provided by the ISO/RTO Standards Review Committee.
Southwest Power Pool Reliability Standards Development Team	No	TOP-001-2, R3 Moderate VSL - the word “affected’ has been omitted and needs to be inserted. TOP-003-2, R1 & R2 - The use of the term ‘element’ in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 - The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn’t this requirement have feathered VSLs such that the more data points missing the more severe the violation would

Organization	Yes or No	Question 4 Comment
		become?
Nebraska Public Power District	No	TOP-001-2, R3 Moderate VSL - the word “affected’ has been omitted and needs to be inserted. TOP-003-2, R1 & R2 - The use of the term ‘element’ in the VSLs for these requirements is confusing. What is an element? Is it restricted to the four items listed under R1 and R2 or could it be multiple items from R1.1 and R2.1 or some combination there of? TOP-003-2, R5 - The single VSL for this requirement is all or none. If a single data point is missing, the violation is Severe. Couldn’t this requirement have feathered VSLs such that the more data points missing the more severe the violation would become?
Response: TOP-001-2 R3 – The SDT agrees and has modified the Moderate VSL. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2 R1 and R2 – The SDT agrees this could cause confusion and has modified the VSLs to use parts in place of elements. This is consistent with the terminology NERC filed with FERC when they eliminated sub-requirements. Thus, the VSLs apply to Parts 1.1 through 1.4 and 2.1 through 2.4. See the redlined VSL in the Summary Consideration for this question to view the changes. TOP-003-2, R5 - The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. No change made.		
Associated Electric Cooperative, Inc.	No	TOP-001-2-R1 VSL Change: “unless such action would violate”To: “and such action would have violated” Rationale: State the issue rather than recite the requirement. TOP-001-2-R8 VSL Change: “whichever is less” To: “whichever is greater” Rationale:

Organization	Yes or No	Question 4 Comment
		Intent TOP-001-2-R10 VSL Change: “has been” To: “had been” Rationale: grammatical TOP-002-3-R1 Lower VSL: Duplicate Severe VSL wording then append “, on one day within a calendar year.” TOP-002-3-R1 Moderate VSL: Duplicate Severe VSL wording then append “, on two non-consecutive days within a calendar year.” TOP-002-3-R1 High VSL: Duplicate Severe VSL wording then append “, on three non-consecutive days or two consecutive days within a calendar year” TOP-002-3-R1 Severe VSL: Append: “, on four or more days, or three consecutive days within a calendar year.” TOP-002-3-R1 VSL changes Rationale: Eliminate zero-defect expectation TOP-002-3-R3 VSL Change: “of the NERC” To: “, whichever is greater, of the NERC” Rationale: precision and alignment with wording in TOP-01-2 R8 VSLs.

Response: TOP-001-2, R1 – The SDT agrees and has modified the VSL similar to your request. See the redlined VSL in the Summary Consideration for this question to view the changes.

TOP-001-2, R8 - The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. The SDT has added an explanatory statement prior to the VSLs for R8 that explains how the VSL is determined. No change made.

TOP-001-2, R10 – The SDT agrees and has corrected the VSL. See the redlined VSL in the Summary Consideration for this question to view the changes.

TOP-002-3, R1 – The SDT disagrees with gradating the VSLs on this requirement. The SDT believes that the requirement is of such importance that it wrote the requirement in singular form. Thus, each failure to have an OPA is a separate violation. This is also consistent with FERC VSL Guidelines. No change made.

TOP-002-3, R3 – The SDT added the missing “whichever is less” language to the Lower VSL. The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. The SDT has added an explanatory statement prior to the VSLs in R3 that explains how the VSL is determined. See the redlined version in the Summary Consideration for this question to see the

Organization	Yes or No	Question 4 Comment
changes.		
Manitoba Hydro	No	TOP-002-3 R3 VSL - The wording of the VSL is unclear. Manitoba Hydro suggests changing the wording of the VSL as follows (the severe VSL of TOP-002-3, R3 is provided as an example): 'The Transmission Operator did not notify either four or more NERC registered entities, or more than 15% of the NERC registered entities identified in the plan(s) as to their role in the plan(s).
Response: The SDT added the missing "whichever is less" language to the Lower VSL. The utilization of the "whichever is less" language has been vetted by NERC and is used in other standards. There is an explanatory statement prior to the VSLs in R3 that explains how the appropriate VSL is determined. See the redlined version in the Summary Consideration for this question to see the changes.		
United Illuminating Company	No	TOP-003 R5 has only a severe VSL. This seems unequitable to the data providors who are responsible for tens of thousands of data points, some redundant. Especially since State Estimators are designed to estimate for bad or missing data. UI disagrees with vsl for R5 which is severe only. UI is concerned that failing to provide a single data point for a partial period would result in a severe violation reagardless of all the other data being transmitted. UI notes that with in TOP-001 (R6 and R8) and TOP-02 R3 the SDT managed to create VSL's that allowed for percentage measure or quantity measure. A similar approch should be done with TOP-003 R5. Failure to transmit a single point of data will not result in a cascade or directly affect the electrical stae of the BES.
Response: The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT		

Organization	Yes or No	Question 4 Comment
believes a single Severe VSL is appropriate. Writing VSLs based on the number of data points provided would further complicate compliance enforcement actions for the responsible entity by requiring them to provide evidence of the number of data points they are required to provide to demonstrate sample size is not practical. No change made.		
South Carolina Electric and Gas	No	
Response: Without a specific comment, the SDT is unable to respond.		
Beaches Energy Services	Negative	It would seem that the VSL for TOP-001 R5 ought to be binary, not informing any TOP of a potential Adverse Reliability Impact seems a Severe violation. It does pose the question, which TOPs? All of them in the interconnect? Only neighboring TOPs? Only TOP's in the RC area? TOP-003 VRFs - there should not be an inconsistency between R1, R2 and R3 for creation and distribution of data specifications being Low VRF, but supplying the data required is a Medium. They should be the same, e.g., if a RC, BA or TOP doesn't tell the other entities what data is required, how can that entity know what to supply? VSLs for R1 and R2, "required element" as used in the VSLs should be replaced with "specifications" to coincide with the term used in the requirement. VSL for R5 should not be binary. It is inconsistent with other requirements. E.g., If in R4, a BA or TOP did not distribute to 3 entities, and therefore did not receive any data from those 3 entities, then, that is a low VRF and High VSL to the BA for missing all of the data from 3 entities. However, in R5 if an entity misses one piece of data from that entity it is a Medium VRF and a Severe VSL. This is inconsistent.
Response: TOP-001, R5 – The SDT disagrees that the VSL ought to be binary. Failure to notify one Transmission Operator of an Adverse Reliability Impact is not as Severe as failing to notify the Reliability Coordinator. Failure to notify the Reliability Coordinator is a Severe VSL. If the Reliability Coordinator knows, then the Reliability Coordinator will ensure the Adverse Reliability Impact is addressed. The answer to the question of which Transmission Operators is found within the requirement. It is the Transmission Operators that are "known or expected" to be affected by the Adverse Reliability Impact. That could be immediate neighbors or		

Organization	Yes or No	Question 4 Comment
broader if the Transmission Operator's operations are "known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas". No change made. TOP-003 – The SDT views development and communication of a data specification as an enabling requirement for ensuring the Transmission Operator and Balancing Authority have the necessary data. Actual supply of the data is what is most important in this requirement. The VRFs reflect this relative importance. No change made. The SDT agrees that "elements" in the VSLs for Requirements R1 and R2 is not the correct word and has modified the VSLs to use parts in place of elements. This is consistent with the terminology NERC filed with FERC when they eliminated sub-requirements. See the redlined version in the Summary Consideration for this question to see the changes. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. Writing VSLs based on the number of data points provided would further complicate compliance enforcement actions for the responsible entity by requiring them to provide evidence of the number of data points they are required to provide to demonstrate sample size and is not practical. No change made.		
California ISO	Negative	The VSL table states the following as Severe for TOP-001 R9: The Transmission Operator exceeded a System Operating Limit (SOL) as identified in Requirement R8 for a continuous duration greater than 30 minutes that would cause a violation of the Facility Rating or Stability criteria. We cannot agree with this wording until the meaning of "continuous" is better defined.
Response: The language quoted in the comment is not from the most recent VSL in TOP-001-2, Requirement R9. For example, the VSL mentions nothing about 30 minutes. The SDT intended the literal meaning of continuous. Thus, the duration would start over if the Transmission Operator managed to temporarily bring the operation of the SOL back within the limit. No change made.		
Florida Municipal Power Agency	Negative	TOP-001-2 R5 and R9 VRFs should be High, especially R9 It would seem that the VSL for R5 ought to be binary, not informing any TOP of a potential Adverse Reliability Impact seems a Severe violation. It does pose the question,

Organization	Yes or No	Question 4 Comment
		which TOPs? All of them in the interconnect? Only neighboring TOPs? Only TOP's in the RC area? The VSL for R8 for Lower, Moderate and High ought to be reworded to avoid the ambiguous reference and make sure that IROLs are always Severe, e.g., (one, two, or three) SOLs that are not IROLS or more than (X% to Y%) .... TOP-002-3 VRF's and VSL's look good TOP-003-2 VRFs - there should not be an inconsistency between R1, R2 and R3 for creation and distribution of data specifications being Low VRF, but supplying the data required is a Medium. They should be the same, e.g., if a RC, BA or TOP doesn't tell the other entities what data is required, how can that entity know what to supply? VSLs for R1 and R2, "required element" as used in the VSLs should be replaced with "specifications" to coincide with the term used in the requirement VSL for R5 should not be binary. It is inconsistent with other requirements. E.g., If in R4, a BA or TOP did not distribute to 3 entities, and therefore did not receive any data from those 3 entities, then, that is a low VRF and High VSL to the BA for missing all of the data from 3 entities. However, in R5 if an entity misses one piece of data fro that entity it is a Medium VRF and a Severe VSL. This is inconsistent.
City of Vero Beach	Negative	TOP-001 R5 and R9 VRFs should be High, especially R9 It would seem that the VSL for R5 ought to be binary, not informing any TOP of a potential Adverse Reliability Impact seems a Severe violation. It does pose the question, which TOPs? All of them in the interconnect? Only neighboring TOPs? Only TOP's in the RC area?

Organization	Yes or No	Question 4 Comment
		The VSL for R8 for Lower, Moderate and High ought to be reworded to avoid the ambiguous reference and make sure that IROLs are always Severe, e.g., (one, two, or three) SOLs that are not IROLS or more than (X% to Y%) .... TOP-003 VRFs - there should not be an inconsistency between R1, R2 and R3 for creation and distribution of data specifications being Low VRF, but supplying the data required is a Medium. They should be the same, e.g., if a RC, BA or TOP doesn't tell the other entities what data is required, how can that entity know what to supply? VSLs for R1 and R2, "required element" as used in the VSLs should be replaced with "specifications" to coincide with the term used in the requirement VSL for R5 should not be binary. It is inconsistent with other requirements. E.g., If in R4, a BA or TOP did not distribute to 3 entities, and therefore did not receive any data from those 3 entities, then, that is a low VRF and High VSL to the BA for missing all of the data from 3 entities. However, in R5 if an entity misses one piece of data from that entity it is a Medium VRF and a Severe VSL. This is inconsistent.

Response: TOP-001, R5 VRF – The SDT disagrees. There is a similar requirement (Requirement R5) in proposed IRO-014-2 that is assigned a Medium VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities: TOP-001-2 for Transmission Operators and IRO-014-2 for Reliability Coordinators. The assignment of the Medium VRF was made based on the premise that failure to coordinate activities, by itself, would not directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures. For a requirement to be assigned a "High" VRF there should be the expectation that failure to meet the required performance "will" result in instability, separation, or cascading failures. This is not the case when an applicable entity fails to coordinate activities. While the SDT agrees that, under some circumstances, it is possible that a failure to coordinate activities may put the applicable entity in a position where it is not as prepared as it should be to address the potential situation, the failure to coordinate would not, by itself, result in instability, separation, or cascading failures. If the applicable entity failed to coordinate activities, it would still be expected to handle the situation if it occurred.

TOP-001-R9, VRF – The SDT disagrees that the VRF should be High for an SOL. SOLs do not have the same level of importance as an IROL. No change made.

Organization	Yes or No	Question 4 Comment
TOP-001, R5 VSL – The SDT disagrees that the VSL ought to be binary. Failure to notify one Transmission Operator of an Adverse Reliability Impact is not as Severe as failing to notify the Reliability Coordinator. Failure to notify the Reliability Coordinator is a Severe VSL. If the Reliability Coordinator knows, then the Reliability Coordinator will ensure the Adverse Reliability Impact is addressed. The answer to the question of which Transmission Operators is found within the requirement. It is the Transmission Operators that are “known or expected” to be affected by the Adverse Reliability Impact. That could be immediate neighbors or broader if the Transmission Operator’s operations are “known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas”. No change made. TOP-001-2, R8 – IROLs are not considered in this requirement. It only pertains to selected, identified SOLs which are not IROLs. No change made. To further clarify the VSLs, a “boiler plate” explanation for how to select the VSL has been added above the VSLs. TOP-003 – The SDT views development and communication of a data specification as an enabling requirement for ensuring the Transmission Operator and Balancing Authority have the necessary data. Actual supply of the data is what is most important in this requirement. The VRFs reflect this relative importance. No change made. TOP-003, R1 and R2 - The SDT agrees that “elements” in the VSLs for Requirements R1 and R2 is not the correct word and has modified the VSLs to use parts in place of elements. This is consistent with the terminology NERC filed with FERC when they eliminated sub-requirements. See the redlined versions in the Summary Consideration for this question to view the changes. The SDT intended for the requirement to represent the give and take that will occur from the Transmission Operator or Balancing Authority to the Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and other Balancing Authorities and Transmission Operators until the data specification is satisfied and violation will likely only occur for non-responsiveness or refusal to provide data. The VSL is intended to represent the satisfaction of the data specification in aggregate. It is not intended to represent failure of small sets of data due to RTU outages, transducer issues, etc. Thus, the SDT believes a single Severe VSL is appropriate. Writing VSLs based on the number of data points provided would further compliance enforcement actions for the responsible entity by requiring them to provide evidence of the number of data points they are required to provide to demonstrate sample size and is not practical. No change made.		
CPS Energy	Negative	Quality Review of VRF's needed.
Response: A quality review of all VRF’s is part of the standard review cycle for all projects.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td>Intellibind</td><td>Negative</td><td>Data retention requirements are not consistent with other standards that only require maintaining logs and voice recordings for 90 days. This adds confusion to compliance recordkeeping where some records are purged every 90 days, but that records of certain topic must be maintainted for longer periods. Retention of data should be done on an identified amount of days (eg. 30, 60, 90) as apposed to "consecutive months" since computer systems primarily use a count of days, and do not necessarily distiguish a calandar month for purging records. As stated the retention period will add addtional adminsitratve overhead and expense to ensuring compliance to these requirements.</td></tr>
<tr><td colspan="3">Response: The general language of the data section is provided by NERC staff. The SDT found only one instance of calendar month in the standards. It stated that voice recordings shall be retained for three calendar months. The SDT changed that reference to 90 calendar days.</td></tr>
<tr><td>Liberty Electric Power</td><td>Negative</td><td>I do not understand why a TO or BA who fails to send a data request to a generator would receive a "Low" VSL while that same generator would receive a "severe" VSL for not satisfying all the requirements of the data request.</td></tr>
<tr><td colspan="3">Response: The SDT views Requirements R1 – R4 as enabling requirements. The purpose of TOP-003-2 is to make sure the Transmission Operator and Balancing Authority have the data necessary for fulfilling their functional obligations. Thus, the real crux of the standard is to supply data. Everything else is simply administrative to enable the sharing of that data. If the generator owner or generator operator does not receive a data specification, they have no obligation under the standards to supply data and cannot be held in violation of the Requirement R5. Thus, no situation could ever exist where a Balancing Authority or Transmission Operator is held in violation of Requirements R3 or R4 for failing to send the data specification to a generator owner or generator operator and then that same generation owner or generation operator is held in violation of Requirement R5. No change made.</td></tr>
<tr><td>Bonneville Power Administration</td><td>Negative</td><td>BPA is voting "No" for VSLs/VRFs for R8 of TOP-001-2, R3 of TOP-002-3, and R3/R4 of TOP-003-2 because they are written in a confusing manner. BPA recommends using 1, 2, 3, or 4 SOLs instead of trying to including things like "more than 10%, but less than 15%", particularly since the requirement is to take the lesser or that or the 1, 2, 3, or 4 SOLs.</td></tr>
<tr><td colspan="3">Response: The utilization of the “whichever is less” language has been vetted by NERC and is used in other standards. There was an explanatory statement prior to the VSLs in some of these requirements that explains how the appropriate VSL is determined. It was</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
missing before others. The explanatory statement has been added where appropriate.		
Ingleside Cogeneration LP - Occidental Chemical Corporation	Yes	Ingleside Cogeneration LP believes that the requirements applicable to a GO/GOP carry VRFs, VSLs, and Time Horizons consistent with those assigned to similar requirements.
NIPSCO	Yes	None at this time
Southwest Power Pool Regional Entity	Yes	
FirstEnergy	Yes	
Imperial Irrigation District (IID)	Yes	
Dominion	Yes	
FMPP	Yes	
Muscatine Power and Water	Yes	
Independent Electricity System Operator	Yes	
Dairyland Power Cooperative	Yes	
Omaha Publc Power District	Yes	
US Bureau of Reclamation	Yes	
Response: Thank you for your support.		

5. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: The majority of comments received for this question were re-statements of earlier comments or simple requests for clarification. No changes were made to any requirements due solely to comments in this question.

Organization	Yes or No	Question 5 Comment
Potomac Electric Power Co.	Abstain	Pepco Holdings Inc. supports the comments offered by EEI.
Response: EEI did not supply comments to this posting.		
Great River Energy	Affirmative	Comments submitted with the MRO NSRF
Minnkota Power Coop. Inc.	Negative	Please see comments submitted by the MRO NSRF.
Response: See the responses to MRO NSRF comments in Q1 – Q4.		
SERC Reliability Corporation	Affirmative	Don't forget to synch the definition of Directive with COM-002.
Response: The SDT is in contact with, and coordinating as necessary, with the SDT that is working on COM-002.		
Florida Municipal Power Pool	Affirmative	Implementation Comments submitted. Added here incase they did not go through. Comments for Project 2007-03 Real-Time Transmission Operations The changes to the TOP Standards are a great improvement over the existing Standards; however, I think because they are so much better than the existing Standards that they should be implemented as soon as possible. I think one year is enough time to make the necessary changes to processes, procedures and documentation. Even more important than the implementation of the new Standards is the deletion of the existing Standards as soon as possible. Some of the existing Requirements are worthless and unenforceable. The SDT has determined that some of the existing

Organization	Yes or No	Question 5 Comment
		Requirements are replaced by new requirements and they will need to be enforceable until the new Requirements are enforceable. However, the SDT has identified some Requirements that are either no longer necessary or covered by existing Requirements or the Functional Model (see mapping document excerpts below): o PER-001-0 R1 o TOP-001-1 R1 o TOP-002-2 R2 o TOP-002-2 R7 o TOP-002-2 R8 o TOP-002-2 R18 o TOP-002-2 R19 Deleting these Requirements does not need to have an implementation period. They can be deleted as soon as approved by FERC with no waiting. TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it never should have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! Also the SDT has identified some Requirements that apply to the Balancing Authority that are either no longer necessary (or even NEVER should have been applicable) or covered by existing Requirements or the Functional Model (see mapping document excerpts below): o TOP-002-2 R1 o TOP-002-2 R5 o TOP-002-2 R6 o TOP-002-2 R10 The SDT states for TOP-002-2 R10: “The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority.” Obvious wrong Requirements like TOP-002-2 R10 should be deleted ASAP. They are a compliance conundrum, and open to compliance fines! From the Mapping Document: PER-001-0 R1 is deleted because “In FERC Order 693a, paragraph 112, the Commission clarifies that a Reliability Coordinator’s authority to issue directives arises out of the Commission’s approval of Reliability Standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and thus it can be deleted.” TOP-001-1 R1 is deleted because “This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn’t alleviate responsibility for actions as each individual requirement in the Reliability Standards now specifies an action and a responsible

Organization	Yes or No	Question 5 Comment
		entity. These needed actions required for reliability of the bulk power system have been more clearly laid out in revised standards. (See FERC Order 693a, paragraph 112.) The requirement is also non-specific, ambiguous, and not performance oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power system is not adversely affected by the deletion of this requirement." TOP-002-2 R1 is deleted for the Balancing Authority because "The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and must take action per approved EOP-002-2.1, Requirement R6 and thus the Balancing Authority part of this sentence can be deleted. Second sentence - Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities as per their certification as NERC registered entities. " TOP-002-2 R2 is deleted because "The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and as such this requirement is no longer needed and can be deleted. " TOP-002-2 R5 is deleted for the Balancing Authority because "The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model." TOP-002-2 R6 is deleted for the Balancing Authority because "The part of this requirement dealing with the Balancing Authority is replaced by approved BAL-002- 0 and proposed BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of

Organization	Yes or No	Question 5 Comment
		operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. " TOP-002-2 R7 is deleted because "The Balancing Authority is required to always plan to meet and recover from Contingency events as stated in approved BAL-002-1, Requirement R2 and therefore this requirement is redundant and can be deleted as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority!" TOP-002-2 R8 is deleted because "The Balancing Authority must be told by the Transmission Operator to take actions regarding reactive power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted as all elements of the requirement are now covered in other standards. Voltage and reactive power balance are the responsibility of the Transmission Operator (not the Balancing Authority) and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority!!" TOP-002-2 R8 is the most important Requirement to be deleted as soon as approved because it should never have been a requirement of the Balancing Authority. To make matters worse this Requirement is in the tier 2 Requirements for actively monitored Requirements for 2012! TOP-002-2 R10 is deleted for the Balancing Authority because "The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary and, thus, this requirement should never have been applicable to the Balancing Authority." TOP-002-2 R18 is deleted because "This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a system reliability issue. " To make matters worse this Requirement is the tier 1 Requirements for actively monitored Requirements for 2012! Which means NERC views this as an important Requirement to reliability. But I agree with the SDT that this Requirement adds NO reliability benefit. TOP-002-2 R19 is deleted because "This is part of an entity's certification and is no longer required in standards. "

Organization	Yes or No	Question 5 Comment
Response: The SDT appreciates your concerns. However, no change is being made due to the following reasons: 1. The requirements being cited are in service today and are being 'followed' by registered entities with minimal problems. The main difference in this project from today is the formalization of some of the requirements particularly the data specification. 2. This is the only comment received on this issue. Other entities are apparently okay with the status quo. **3.** Setting up an implementation plan with the suggestions above would make for a logistical nightmare with no reliability benefit. **4.** The SDT has shortened the effective date to 12 months for all requirements except the proposed TOP-003-2, Requirements R1 and R2 which will be 10 months.		
MEAG Power	Affirmative	MEAG Power supports the comments of Austin Energy.
Response: Austin Energy did not supply any comments to this posting.		
Portland General Electric Co.	Affirmative	PGE agrees with the WECC Position paper on Real-Time Operations.
Response: Without specific comments to this posting the SDT is unable to respond.		
Illinois Municipal Electric Agency		Illinois Municipal Electric Agency appreciates SDT efforts to develop a sixth draft for this proposed Reliability Standards development. While we realize the SDT will never be able to resolve all concerns, it appears from our own review and our review of other entity comments that additional revisions are needed to achieve a level of quality that will minimize difficulties complying with these Reliability Standards.
Baltimore Gas & Electric Company, Constellation Energy Commodities Group	Affirmative	We are voting affirmatively because we support the improvements achieved by the drafting team work so far. However, we raised remaining concerns with the standard proposal on the comment form submitted on behalf of CCG, CECD and CPG. We expect the drafting team to continue to make clarifying changes until the end of this stakeholder process. The greater the clarity in the final product, the less risk of contradictory perspectives on compliance.

Organization	Yes or No	Question 5 Comment
Response: The SDT will continue to work to refine the standards until the end of the stakeholder process.		
Santee Cooper	Negative	"Internal area reliability" needs to be clarified.
Response: Requirement R8 was modified to replace the phrase "its internal area reliability" with "reliability internal to its Transmission Operator Area". **R8.** Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL~~s~~, ~~have~~has been identified by the Transmission Operator as supporting ~~its internal area~~ reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis.		
Fort Pierce Utilities Authority	Negative	Please see the joint comments submitted by Florida Municipal Power Agency (FMPA) filed through the formal comment process.
Response: See response to FMPA comments in Q1 – Q4.		
Consolidated Edison Co. of NY, Inc.		Comments: TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for "Reliability Directive" changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an "across the board" usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts." It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts

Organization	Yes or No	Question 5 Comment
		compliance to COM-002.
Orange and Rockland Utilities, Inc.		Comments: TOP-001-2 is referencing a NERC definition for “Reliability Directive” which is not in effect today and is listed on the Definitions of Terms Used in Standard, page 2. It is stated that the definition of “Reliability Directive” would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for “Reliability Directive” changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an “across the board” usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: “A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.” It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team as well.		
Georgia System Operations		GSOC believes that all 3 standards should be voted on together in one vote. They are too inter-related. One or two of these should not be approved if one of them is not approved.
Response: The purpose of separating the votes at this stage was to provide additional feedback to the SDT. The three standards will be filed together once all 3 have been approved by the industry.		
Texas Reliability Entity		Referring to the posted “Issues Database,” under Order 693 Â¶ 1604/1608, the red-lined language is not actually in the referenced requirement. Does the drafting team

Organization	Yes or No	Question 5 Comment
		contend that the proposed requirements satisfy this FERC directive? Referring to the posted “Issues Database,” under Order 693 Â¶ 1636 (TOP-004), this document suggests that a 30-minute limit is contained in the requirements, but that limit is not in the language that is now posted. Does the drafting team contend that the proposed requirements satisfy this FERC directive? In general, NERC needs to make sure the Issues Database is consistent with the latest draft of the requirements. The VRF/VSL Assignment Document needs to be cleaned up. There are numerous references to incorrect requirement numbers. On page 3, TOP-001-2 Requirement R3 is struck from the list of “High” VRFs, but it is assigned a high VRF in the posted standard. Also, the title of TOP-001-2 is stated incorrectly in this document (at the beginning).
Response: 1604 - The SDT agrees that the posted language was not updated in the issues database to reflect the latest version of the standard. However, the context hasn’t changed and the SDT does believe that the suggested requirement addresses the directive. The issues database language has been cleaned up appropriately. No other change made. 1636 – The issues database language was not properly updated when the requirement was changed from a 30 minute perspective to a limits perspective. However, the context hasn’t changed and the SDT does believe that the suggested requirement addresses the directive. The issues database language has been cleaned up appropriately. No other change made. The SDT has reviewed the VRF/VSL document and made changes as appropriate. The SDT does not understand the comment. The posted requirement is assigned a high VRF. The VRF/VSL document states that Requirement R3 has been assigned a high VRF. There does not appear to be a discrepancy. No change made. The title has been corrected in the VRF/VSL document.		
American Transmission Company, LLC		ATC feels this project has diminished a good base of existing standards, and introduced ambiguity, and vagueness. Additionally, we feel certain key aspects of the current standards were removed for example, “Clear, decision making authority” from System Operators, and the need for “Uniform Line Identifiers”, which is not in

Organization	Yes or No	Question 5 Comment
		the interest of Reliability.
Response: The SDT has provided reasons for deleting the two phrases referenced above in the mapping document accompanying this posting. To date, the SDT has seen no justifications for restoring the cited phrases. No change made.		
SERC OC Standards Review Group		Data retention requirements for TOP-001-2. TOP-002-3 and TOP-0003-2 need to align with the expectations of the compliance entity."The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Standards Review group only and should not be construed as the position of SERC Reliability Corporation, its board or its officers."
Owensboro Municipal Utilities	Negative	Please refer to SERC Operating Committee Comments.
Entergy, Entergy Services, Inc.	Negative	o Comments submitted - see SERC OC Standards Review Group comments.
Response: The data retention requirements for all 3 standards follow the established guidelines and were reviewed as part of the quality review process prior to posting. No change made.		
GTC		Demonstrating providing all data specifications for real time operations horizon is very prescriptive in nature and could have unanticipated "compliance documentation" consequences when data or the transfer method is unavailable (e.g., when an RTU goes down).
Response: Demonstrating the need would be an onerous task with no reliability benefit. The Transmission Operator and Balancing Authority are constrained as to what they can request by the language in the requirements. They can only ask for what is needed to support their assigned tasks. No change made.		
FirstEnergy		FE has the following comments and suggestions:1. In the mapping document, it shows that PRC-001-1 R2 will be replaced by the new TOP-003-2 R5. However, we do not see a new version of PRC-001-2 posted. Also, the implementation plan makes no reference to PRC-001.

Organization	Yes or No	Question 5 Comment
		2. The mapping document does not seem to be referencing the correct version of TOP-005 (should be Version 2a). Also, the mapping document is not referencing the correct requirement for TOP-006-1 R4 (the RC should not be shown as applicable).
Response: The PRC standard was inadvertently left out of this posting but has been provided as part of the next posting. The Implementation Plan has been updated as well. The correct reference should be TOP-005-2a and the mapping document has been changed as necessary to reflect this. Requirement R4 has been corrected.		
NV Energy		In the re-draft of these three standards, TOP-001, -002, and -003, we seem to have lost the concept of Planned Outage Coordination for BES facilities (a whole Standard was devoted to the process). In viewing the mapping document, it is stated that the requirements for such outage coordination that used to reside in TOP-003-1 are now replaced by R1 and R2 of TOP-003-2. If this is the case, then all of the activities of outage coordination are to be encapsulated in the clause "documented specification for the data necessary for it to perform its required Operational Planning Analyses..." While it may be covered in this extremely broad clause, the SDT nevertheless gave prominence to the coordination of telemetry outages within a specific requirement R6 of TOP-001-2. If telemetry outages have a separate requirement, then shouldn't planned outage coordination of BES facilities rise to the level of importance that would merit its own requirement?
Response: Since telemetry outages might take out the very mechanism relied upon for the transfer of data in TOP-003-2, the SDT believed that a separate requirement was necessary for such outages. Also, telemetry is part of infrastructure and not a type of data so it is handled separately. No change made.		
PacifiCorp		PacifiCorp would like to express their appreciation to the SDT for their efforts. This consolidation effort has resulted in a more streamlined approach to this set of interrelated NERC Reliability Standards. PacifiCorp would recommend that NERC

Organization	Yes or No	Question 5 Comment
		consider other sets of standards for which such a consolidation effort would be mutually beneficial to NERC and stakeholders, from both a compliance and administrative standpoint.
Response: Thank you for your support.		
Dominion		Page 1 and Page 15 of the Violation Risk Factor and Violation Severity Level Assignments document, titles reads; Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-2, TOP-003-2:, Dominion suggests changing TOP-002-2 to TOP-002-3.
Response: The suggested correction has been made.		
Pepco Holdings Inc		PHI supports the comments provided by the ISO/RTO Standards Review Committee.
ISO/RTO Standards Review Committee		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Midwest ISO, Inc.	Affirmative	Please See SRC Comments Submitted
New Brunswick System Operator	Negative	Please see comments submitted by the NPCC Reliability Standards Committee and IRC/SRC
Southwest Power Pool Reliability Standards Development Team		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
City Utilities of Springfield, Missouri	Negative	City Utilities of Springfield, Missouri supports the comments of SPP.

Organization	Yes or No	Question 5 Comment
Empire District Electric Co.	Negative	EDE agrees with the comments provided by SPP RTO
ISO New England Inc.		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Nebraska Public Power District		The definition of Reliability Directive is contained in COM-002-3 and that standard hasn't been posted for comment/ballot at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved?
Constellation Energy		The definition of Reliability Directive is contained in COM-002-3 which has not been approved at this time. What happens if the TOP standards are approved and the COM-002-3 standard is subsequently not approved or change? Since the two projects appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently.
Northeast Power Coordinating Council		TOP-001-2 is referencing a NERC definition for "Reliability Directive" which is not in effect today and is listed on the Definitions of Terms Used in Standard Section on page 2. It is stated that the definition of "Reliability Directive" would be written by the Reliability Coordinator Standards Drafting Team (Project 2006-06), and post it for vetting by the industry sometime in the future. If this standard is approved now and the definition for "Reliability Directive" changes because of the Project 2006-06 work, the TOP standards will have to be revisited. The Project 2006-06 Drafting Team should be coordinating its work with this project to develop an "across the board" usable definition. This Comment Form states under Background Information: o The definition of Reliability Directive has been modified by Project 2006-06 to read as follows: "A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is

Organization	Yes or No	Question 5 Comment
		necessary to address an Emergency or Adverse Reliability Impacts." It is not apparent where the 2006-06 team added "Adverse Reliability Impacts" to the definition. This change also impacts compliance to COM-002.
Response: The SDT is coordinating with Project 2006-06 (RC SDT) which is being balloted at this time. Implementation will be coordinated with that team as well.		
Southwest Power Pool Regional Entity		The standards being proposed are not sufficient to replace the requirements of the 9 standards being retired by this project. The requirements listed below are not covered by the new standards. TOP-001-1 R5. New requirement (TOP-001-2 R11) does not cover "take actions to avoid when possible or mitigate the emergency." Pre-emptive action is an important part of preventing cascading outages. The proposed TOP-001-2 R11 only deals with real time violations. The SDT is relying upon IRO-001-3 being approved in order to retire some of these requirements; however, this has not yet been passed by industry. TOP-002-2R1. If conditions change on the current day, where in the proposed standards is a new operating plan required to prepare for the next contingency or identify new SOLs? R6. Which of the proposed standards obligate the TOP to continuously plan for the next N-1 event? R13. MOD-024 and MOD-025 (which would replace this requirement) were not approved by FERC in the initial set of standards. A replacement standard MOD-025-2 has been posted for comment, but has not had an initial ballot. TOP-004-2R1. The proposed TOP-001-2, R7 and R9, only requires IROLs and certain SOLs be respected. The requirement being retired applied to all SOLs. This reduces BES reliability. R4. This covers cases where no Operational Planning Assessment is available to

Organization	Yes or No	Question 5 Comment
		ensure the system is in a safe state. The proposed TOP-002-3 does not include any requirement about when a new study is needed. TOP-006-2R5., R6., R7. The SDT is relying on the certification process to justify the retirement of these requirements. However, the Certification Process only looks at approved applicable Reliability Standards. If these are retired, these will no longer be reviewed by the Certification Team. TOP-008-1R2. The current language in TOP-008-1, R2 of "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" is different than the proposed language of TOP-001-2, R7 and R9 "shall not operate outside the IROL (or SOL)". We recommend incorporating the "shall operate to prevent the likelihood that a disturbance will result in an IROL violation" into TOP-001-2 R7. PER-001-0R1. The existing requirement specifically places the responsibility on the personnel on shift not on the senior management. This does not appear to be covered by any other requirement. PRC-001-1 R2. The obligation to take corrective actions for protection relay or equipment failures is not covered by the proposed TOP-003-2 standard.

Response: TOP-001-1, R5: For anticipated conditions, the proposed TOP-002-3, Requirements R2 and R3 require the TOP to "develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1." The proposed TOP-001-2, Requirement R11 requires each Transmission Operator to "act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8." When the exceedance anticipated in the assessment of the Operational Planning Analysis in proposed TOP-002-3, Requirement R1 becomes an actual exceedance in Real-time operations, the plan that the Transmission Operator developed per proposed TOP-002-3, Requirements R2 and R3 is to be implemented. Thus, the possible appropriate action to take, according to proposed TOP-001-2, Requirement R11 is to "act or direct others to act" in accordance with the plan that addresses the exceedance. Of course, this is all accomplished in accordance with the Reliability Coordinator as per approved IRO-008-1. No change made.

IRO-001-3: The SDT understands the timing and coordination issues involved with IRO-001-3 and is working closely with Project 2006-

Organization	Yes or No	Question 5 Comment
06 in this regard. TOP-002-2, R1: TOP-002-3 uses Operational Planning Analysis which includes contingency planning. The SDT believes that this will incorporate most of the situations that will occur in real-time. If something comes along that wasn't in the plan the language doesn't preclude an entity running a new analysis. No change made. TOP-002-2, R6: Requirement R6 does not mandate continuous planning. The mapping document shows how the SDT is proposing replacing this requirement. No change made. TOP-002-2, R13: The SDT is aware of the coordination issues involved and will take appropriate actions when, and if, required to make certain that there is no reliability gap created. TOP-004-2, R1: The SDT has provided the reasoning for the handling of SOLs repeatedly over the life of the project. The majority of the industry is on board with these changes as seen in provided comments. The SDT believes that the suggested changes do not adversely affect reliability. No change made. TOP-004-2, R4: The old Requirement R4 does not say anything about a new study. The SDT believes that the mapping shown for this requirement clearly covers the situation. No change made. TOP-006-2, R5: The certification process is not necessarily restricted to existing requirements. In deleting requirements based on certification, the SDT is responding to guidance received from NERC staff which has instructed SDTs to delete requirements that can and will be shown as initial capabilities during certification. In addition, where such requirements have been deleted in this project, the mapping document always shows where other remaining requirements would be violated if the core certification requirements aren't met and maintained. Therefore, no reliability gap is created. No change made. TOP-008-1, R2: Any pre-emptive actions for IROLs are the responsibility of the Reliability Coordinator as per the approved IRO standards. No change made. PER-001-0, R1: The SDT proposed in the first posting of this project that such a requirement is no longer needed in standards as cited in the posted mapping document. No change made. PRC-001-1, R2: There is no wording here for corrective actions. That is covered in PRC-004-2a, Requirement R2. No change made.		
South Carolina Electric and Gas		There is a mistake in the mapping document for TOP-001-2 R11 as the language doesn't match the language in the Standard. There is additional language in the mapping document that states "within 30 minutes," which the standard does not,

Organization	Yes or No	Question 5 Comment
		and should not say. This occurs on page 36 for the mapping of current TOP-007 R2 to proposed TOP-001-2 R11. Additonally, SCE&G believes that it would be erroneous to remove TOP-004 R5 on the basis of the functional model. The functional model for the TOP stipulates that the TOP "is responsible for the real-time operating reliability of the transmission assets under its purview, which is referred to as the Transmission Operator Area. The Transmission Operator has the authority to take certain actions to ensure that its Transmission Operator Area operates reliably." If a situation were to arise where there was not sufficient time to contact the RC or if the RC was taking action that would put the TOP in jeopardy, SCE&G believes that the TOP has the right to separate from the Interconnection to protect the reliability of its system as is spelled out in current standard TOP-005 R5.
Response: The mapping document language was not properly updated when the requirement was changed from a 30 minute perspective to a limits perspective. However, the context hasn't changed and the SDT does believe that the suggested requirement addresses the issue. The mapping document has been cleaned up appropriately. No other change made. The SDT is not basing the deletion of this requirement solely on the Functional Model. Good operating practice would dictate such a deletion as well. The SDT believes that separation must be under the control of the Reliability Coordinator. No change made.		
Xcel Energy		There is reference in each draft standard to deleting some requirements from PRC-001 but those proposed changes are not show in any proposed drafts or implementation plans (only 1 PRC-001 requirement is listed in the implementation plan).
Response: The PRC standard was inadvertently left out of this posting but has been provided as part of the next posting. The Implementation Plan has been updated as well.		
Western Area Power Administration		TOP 1 and 2 as written are generally acceptable. TOP 3 opens doors for manipulation.

Organization	Yes or No	Question 5 Comment
Response: Without specific comments, the SDT is unable to respond.		
The Valley Group, a Nexans Company		TOP-004-2 R4:If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits, as determined by System Operating Limits or real-time measurements, have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits (SOLs or Real-Time Limits) within 30 minutes. TOP-006-2 R1.2Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources, as determined with SOLs or Real-Time Calculated limits, available for use. TOP-006-2 R2:Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real time operating capacity, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. TOP-008-1 R2:Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall operate the Bulk Electric System to the actual real-time limits (if available) or the most limiting derived parameter. TOP-008-1 R3:The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. The Transmission Operator shall review the real time status and capacity of transmission facility prior to disconnecting, if applicable. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

Organization	Yes or No	Question 5 Comment
		TOP-008-1 R4:The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation. If applicable, and prior to immediate mitigation, the Transmission Operator shall review real time status and capacity of the equipment, and based on those, made necessary adjustments.
Response: The SDT does not understand the comment which appears to be a cut and paste of some existing requirements with no suggestions. No change made.		
Ameren		We highly recommend that you do not lump requirements that include SOL with IROL. IROLs by definition should have VRFs higher than SOL. So it is not possible to properly assign the VRF consistent with the NERC VRF/VSL Guideline documents. We would suggest that the SDT could review what the FAC-003 SDT has done and then provide separate Requirements when there are known and expected VRF differences for different elements covered by a combined Requirement.
Response: In this case, the SOLs being referenced are specifically, and explicitly, identified as important to a local area. This does not equate an SOL to an IROL but does imply common handling of the VRF. No change made.		
BGE		We realize that SDT for Project 2006-06 is responsible for defining Reliability Directive; however, we would like to reiterate our position that the definition must capture the identification concept that is reflected in Requirement (R1). As a result, when Reliability Directive is used elsewhere, it would be clear that the communication must be identified as a Reliability Directive. Additionally, the currently proposed definition of Reliability Directive is also contained in COM-002-3 and IRO-001-3 which have not been approved at this time. What happens if the TOP standards are approved and the COM and IRO standards are subsequently not approved or change? The revised definition should stay with each of the 3 standards until it is in the Glossary of Terms. Since the two projects

Organization	Yes or No	Question 5 Comment
		appear to be on similar timelines for stakeholder approval, we suggest that the two drafting teams (Projects 2007-03 and 2006-06) coordinate presentation of the standard revisions for NERC Board approval to occur at the same time. Likewise, NERC should file both for FERC approval concurrently. We are voting affirmatively because we support the improvements achieved by the drafting team work so far. However, we raised remaining concerns with the standard proposal on the comment form submitted on behalf of BGE. We expect the drafting team to continue to make clarifying changes until the end of this stakeholder process. The greater the clarity in the final product, the less risk of contradictory perspectives on compliance.
Response: Your suggestion has been forwarded to Project 2006-06. The SDT is coordinating activities with Project 2006-06 in this regard. The SDT will continue to work to refine the standards until the end of the stakeholder process.		

END OF REPORT

Standard Development Roadmap

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2. SAR version 1 comment period closed on June 13, 2007.
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1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated on a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

A. Introduction

1. **Title:** **Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

   4.5. Load-Serving Entity

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities..

B. Requirements

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning,]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence that it complied with each Reliability Directive issued and identified as such by the Transmission Operator(s) unless such action would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M2. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified, Reliability Directive(s) issued in accordance with Requirement R2. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M3. Each Transmission Operator shall make available, upon request, evidence that it has informed its Reliability Coordinator and Transmission Operators that it knew or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M4. Each Transmission Operator shall make available, upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4, unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M5. Each Transmission Operator shall make available, upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5, unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M6. Each Balancing Authority and Transmission Operator shall make available, upon request, evidence that it notified its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Balancing Authority or Transmission Operator may provide an attestation that an event has not occurred.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include, but is not limited to, an electronic or hard copy of information from the Operational Planning Analysis used in its assessment, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration that would cause a violation of the Facility

Rating or Stability criteria upon which it is based, as specified in Requirement R8 and in Requirement R9. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8, in accordance with Requirement R11. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year,

with the exception of voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, and such action would not have violated safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
For the Requirement R3, R5, R6, and R8 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting

	Lower	Moderate	High	Severe
				entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R5	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform its Reliability Coordinator of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
R6	The responsible entity did not notify one negatively-impacted interconnected NERC-registered entity, or 5% or less of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively-impacted interconnected NERC-registered entities, or more than 5% and less than or equal to 10% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify three negatively-impacted interconnected NERC-registered entities, or more than 10% and less than or equal to 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more negatively-impacted interconnected NERC-registered entities, or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and

	Lower	Moderate	High	Severe
				control equipment and associated communication channels between the affected entities.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs, or more than 5% and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs, or more than 10% and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs, or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL), as identified in Requirement R8, for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, had been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's

	Lower	Moderate	High	Severe
				$T_{v,}$ or of an SOL identified in Requirement R8.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

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2. **Number:** TOP-001-2

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   4.2. Transmission Operator

   4.3. Generator Operator

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R2. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning,]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

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Rationale: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

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M1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence that it complied with each Reliability Directive issued and identified as such by the Transmission Operator(s) unless such action would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M2. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified, Reliability Directive(s) issued in accordance with Requirement R2. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M3. Each Transmission Operator shall make available, upon request, evidence that it has informed its Reliability Coordinator and Transmission Operators that it knew or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M4. Each Transmission Operator shall make available, upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4, unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M5. Each Transmission Operator shall make available, upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5, unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M6. Each Balancing Authority and Transmission Operator shall make available, upon request, evidence that it notified its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Balancing Authority or Transmission Operator may provide an attestation that an event has not occurred.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include, but is not limited to, an electronic or hard copy of information from the Operational Planning Analysis used in its assessment, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration that would cause a violation of the Facility

Rating or Stability criteria upon which it is based, as specified in Requirement R8 and in Requirement R9. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8, in accordance with Requirement R11. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year,

with the exception of voice recordings which shall be retained for a minimum of ~~ninety~~ 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

<table>
<tr><th></th><th>Lower</th><th>Moderate</th><th>High</th><th>Severe</th></tr>
<tr><td>R1</td><td>N/A</td><td>N/A</td><td>N/A</td><td>The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, and such action would not have violated safety, equipment, regulatory, or statutory requirements.</td></tr>
<tr><td>R2</td><td>N/A</td><td>N/A</td><td>N/A</td><td>The responsible entity did not inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.</td></tr>
<tr><td colspan="5">For the Requirement R3, R5, R6, and R8 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.</td></tr>
<tr><td>R3</td><td>The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.</td><td>The Transmission Operator did not inform two other Transmission Operators, or more than 5% ~~or~~and less than or equal to 10% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.</td><td>The Transmission Operator did not inform three other Transmission Operators, or more than 10% ~~or~~and less than or equal to 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.</td><td>The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis.
OR
The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is ~~less, that~~less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.</td></tr>
<tr><td>R4</td><td>N/A</td><td>N/A</td><td>N/A</td><td>The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting</td></tr>
</table>

	Lower	Moderate	High	Severe
				entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R5	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% ~~or~~and less than or equal to 10% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% ~~or~~and less than or equal to 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform its Reliability Coordinator of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
R6	The responsible entity did not notify one negatively-impacted interconnected NERC-registered entity, or 5% or less of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively-impacted interconnected NERC-registered entities, or more than 5% ~~or~~and less than or equal to 10% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify three negatively-impacted interconnected NERC-registered entities, or more than 10% ~~or~~and less than or equal to 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more negatively-impacted interconnected NERC-registered entities, or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and

	Lower	Moderate	High	Severe
				control equipment and associated communication channels between the affected entities.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
~~For the Requirement R8 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.~~				
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs, or more than 5% ~~or~~and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs, or more than 10% ~~or~~and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs, or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL), as identified in Requirement R8, for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, had been exceeded.

	Lower	Moderate	High	Severe
R11	N/A	N/A	N/A	The Transmission Operator did not act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's $T_{v,}$ or of an SOL identified in Requirement R8.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

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12. Seventh posting of revised standard on March 22, 2012.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that three requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements and will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that Transmission Operators have plans for operating within specified limits.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include, but is not limited to, dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include, but it is not limited to, plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement for a rolling six-month period for analyses, the most recent 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis that represented projected System conditions allowing it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one NERC-registered entity, or 5% or less of the	The Transmission Operator did not notify two NERC-registered entities, or more than 5%, and	The Transmission Operator did not notify three NERC-registered entities, or more than 10% and	The Transmission Operator did not notify four or more NERC-registered entities, or more

	NERC-registered entities, whichever is less identified in the plan(s) cited, as to their role in the plan(s).	less than or equal to 10% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	less than or equal to 15% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	than15% of the NERC-registered entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

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A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that Transmission Operators have plans for operating within specified limits.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include, but is not limited to, dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include, but it is not limited to, plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

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Each Transmission Operator shall keep data or evidence to show compliance for each Requirement for a rolling six~~-~~month period for analyses, the most recent ~~three months~~90 calendar days for voice recordings, and 12 months for operating logs and e-mail records, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis that represented projected System conditions allowing it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one NERC-registered entity, or 5% or less of the	The Transmission Operator did not notify two NERC-registered entities, or more than 5%, and	The Transmission Operator did not notify three NERC-registered entities, or more than	The Transmission Operator did not notify four or more NERC-registered entities, or more

	NERC-registered entities, whichever is less identified in the plan(s) cited, as to their role in the plan(s).	less than or equal to 10% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	10% and less than or equal to 15% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	than15% of the NERC-registered entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

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12. Seventh posting of revised standard on March 22, 2012.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008, following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that three requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements and will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their operational planning and Real-time monitoring responsibilities.

4. **Applicability**

   4.1. Transmission Operator.

   4.2. Balancing Authority.

   4.3. Generator Owner.

   4.4. Generator Operator.

   4.5. Interchange Authority.

   4.6. Load-Serving Entity.

   4.7. Transmission Owner.

   4.8. Distribution Provider.

5. **Effective Date:** All requirements, except Requirement R5, will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements, except Requirement R5, become effective the first day of the first calendar quarter ten months following Board of Trustees' adoption. Requirement R5 will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R5 becomes effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

1.2. A mutually-agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. A mutually-agreeable format.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

R3. Each Transmission Operator shall distribute its data specification, as developed in Requirement R1,to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority shall distribute its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall make available its dated, current, in-force documented specification for data in accordance with Requirement R1.

M2. Each Balancing Authority shall make available its dated, current, in-force documented specification for data in accordance with Requirement R2.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification, as developed in Requirement R1,to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their Operational Planning Analyses and Real-time monitoring, in accordance with Requirement R1 and Measurement M1, as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their analysis functions and Real-time monitoring, in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R1 to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90 calendar days that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.
R2	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring. OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring	The Transmission Operator did not distribute its data specification, as developed in requirement R1 to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring

	process used in meeting its NERC-mandated reliability requirements.	Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	process used in meeting its NERC-mandated reliability requirements.
For the Requirement R4 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R4	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements .	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to four or more entities, or more than 15% of the entities, whichever is less,that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.
R5	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.
11. Sixth posting of revised standard on December 14, 2011.
~~11.~~12. Seventh posting of revised standard on March 22, 2012.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008, following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. -As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that ~~3~~ three requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements and will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	~~3~~2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their operational planning and Real-time monitoring responsibilities.

4. **Applicability**

   4.1. Transmission Operator.

   4.2. Balancing Authority.

   4.3. Generator Owner.

   4.4. Generator Operator.

   4.5. Interchange Authority.

   4.6. Load-Serving Entity.

   4.7. Transmission Owner.

   4.8. Distribution Provider

5. **Effective Date:** All requirements, except Requirement R5, will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements, except Requirement R5, become effective the first day of the first calendar quarter ten months following Board of Trustees' adoption. -Requirement R5 will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R5 becomes effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

1.2. A mutually ~~-~~agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. A mutually ~~-~~agreeable format.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

R3. Each Transmission Operator shall distribute its data specification, as developed in Requirement R1, to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority shall distribute its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall make available its dated, current, in-~~-~~force documented specification for data in accordance with Requirement R1.

M2. Each Balancing Authority shall make available its dated, current, in-~~-~~force documented specification for data in accordance with Requirement R2.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification, as developed in Requirement R1, to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator shall retain its dated, current, in-~~-~~force, documented specification for the data necessary for it to perform their Operational Planning Analyses and Real-time monitoring, in accordance with Requirement R1 and Measurement M1, as well as any documents in force since the last compliance audit.
- Each Balancing Authority shall retain its dated, current, in-~~-~~force, documented specification for the data necessary for it to perform their analysis functions and Real-time monitoring, in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.
- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R1 to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R3 and Measurement M3.
- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90 calendar days that it has satisfied the obligations of the documented specifications for data~~,~~ in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.
R2	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring. OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring	The Transmission Operator did not distribute its data specification, as developed in requirement R1 to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring

	process used in meeting its NERC-mandated reliability requirements.	Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	process used in meeting its NERC-mandated reliability requirements.
For the Requirement R4 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R4	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements~~-~~.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements .	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to four or more entities, or more than 15% of the entities, whichever is less,that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.
R5	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

E. **Regional Variances**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2007-03 Real-time Operations

Prerequisite Approvals

Some changes made in this project are dependent on corresponding changes being approved in:

- Project 2006-06, Reliability Coordination:
  - IRO-001-3 - Reliability Coordination – Responsibilities and Authorities
  - IRO-005-4 - Reliability Coordination – Current Day Operations
- Project 2007-09, Generator Verification:
  - MOD-025-2 - Verification and Data Reporting of Generator Real and Reactive Power Capability

TOP-001-2: Transmission Operations, TOP-002-3: Operations Planning and TOP-003-1: Operational Reliability Data cannot be implemented until all three of the above standards have been implemented.

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

Two drafting teams (Project 2006-06 and Project 2007-03) have coordinated on a common definition of Reliability Directive and agreed that the Reliability Coordination Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference.

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

Compliance with Standard

There are three standards associated with this project for which industry approval will be requested: TOP-001-2: Transmission Operations, TOP-002-3: Operations Planning, and TOP-003-1: Operational Reliability Data.

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							

TOP-001-2: Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X	X	X
TOP-004-2: Real-Time Transmission Operations	Retired							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-1: Response to Transmission Limit Violations	Retired							
PRC-001-2	Retired Requirements R2, R5, and R6.							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

Effective Date of Revised Standards

All requirements except TOP-003-2, Requirements R1 and R2 will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements except TOP-003-2, Requirements R1 and R2 become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Requirements R1 and R2 of TOP-003-2 will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R2 of TOP-003-2 become effective the first day of the first calendar quarter ten months following Board of Trustees approval.

The twelve month period is to allow for entities to update processes and train operators on the revised requirements. The two month differential for TOP-003-2, Requirements R1 and R2 is to provide time for recipients of a data specification to respond to the request for data.

Retirement Date for Existing Standards

The existing Standards shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements will be retired at midnight of the day immediately prior to the first day of the first calendar quarter twelve months following Board of Trustees adoption.

Implementation Plan

Project 2007-03 Real-time Operations

Prerequisite Approvals

Some changes made in this project are dependent on corresponding changes being approved in:

- Project 2006-06, Reliability Coordination:
  - IRO-001-3~~:~~ - Reliability Coordination – Responsibilities and Authorities
  - IRO-005-4~~:~~ - Reliability Coordination – Current Day Operations
- Project 2007-09, Generator Verification:
  - MOD-025-2 - Verification and Data Reporting of Generator Real and Reactive Power Capability

TOP-001-2: Transmission Operations, TOP-002-3: Operations Planning and TOP-003-1: Operational Reliability Data cannot be implemented until all three of the above standards have been implemented.

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

Two drafting teams (Project 2006-06 and Project 2007-03) have coordinated on a common definition of Reliability Directive and agreed that the Reliability Coordination Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference.

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

Compliance with Standard

There are three standards associated with this project for which industry approval will be requested: TOP-001-2: Transmission Operations, TOP-002-3: Operations Planning, and TOP-003-1: Operational Reliability Data.

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							

TOP-001-2: Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X	X	X
TOP-004-2: Real-Time Transmission Operations	Retired							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-1: Response to Transmission Limit Violations	Retired							
PRC-001-2	Retired Requirements R2, R5, and R6.							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

Effective Date of Revised Standards

All requirements except TOP-003-2, Requirements R1 and R2 will become effective the first day of the first calendar quarter ~~twenty-four~~twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements except TOP-003-2, Requirements R1 and R2 become effective the first day of the first calendar quarter ~~twenty-four~~twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Requirements R1 and R2 of TOP-003-2 will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R2 of TOP-003-2 become effective the first day of the first calendar quarter ten months following Board of Trustees approval.

The ~~twenty-four~~twelve month period is to allow for entities to update processes~~, develop data specifications,~~ and train operators on the revised requirements. The two month differential for TOP-

003-2, Requirements R1 and R2 is to provide time for recipients of a data specification to respond to the request for data.

Retirement Date for Existing Standards

The existing Standards shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter ~~twenty-four~~twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements will be retired at midnight of the day immediately prior to the first day of the first calendar quarter ~~twenty-four~~twelve months following Board of Trustees adoption.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Note: The Project 2007-03 SDT is recommending retirement of three requirements in PRC-001-1 because those requirements address data and data requirements, which is covered in TOP-003-2. This redline shows the retired requirements, and a mapping document showing the approved requirements in PRC-001 and the proposed disposition of those requirements is posted on the Project 2007-03 page. The ballot of the conforming changes to PRC-001 is associated with the approval of TOP-003-2 and the implementation plan for this project.

More complete revisions to PRC-001 are addressed in the scope of Project 2007-06 SDT.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.
11. Sixth posting of revised standard on December 14, 2011.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that 3 requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	3Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-2

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. *[Violation Risk factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R2.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R2.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 2, 2.1, and 2.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Compliance Monitoring and Assessment Processes

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)

- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
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1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Reqmt. #	VRF	Time Horizon	Lower	Moderate	High	Severe
R1	High	Operations Planning, Same-day Operations, Real-time Operations	N/A	N/A	The responsible entity failed to be familiar with the limitations of protection system schemes applied in its area.	The responsible entity failed to be familiar with the purpose of protection system schemes applied in its area.
R2	N/A	N/A	N/A	N/A	N/A	N/A
R2.1	High	Operations Planning, Same-day Operations, Real-time Operations	The Generator Operator failed to coordinate one new protective system or protective system change with either its Transmission Operator or its Host Balancing Authority or both.	The Generator Operator failed to coordinate two new protective systems or protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate three new protective systems or protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate more than three new protective systems or protective system changes with its Transmission Operator or its Host Balancing Authority, or both.
R2.2	High	Operations Planning, Same-day Operations, Real-time Operations	The Transmission Operator failed to coordinate one new protective system or protective system change with neighboring Transmission Operators or Balancing Authorities or both.	The Transmission Operator failed to coordinate two new protective systems or protective system changes with neighboring Transmission Operators or Balancing Authorities or both.	The Transmission Operator failed to coordinate three new protective systems or protective system changes with neighboring Transmission Operators or Balancing Authorities or both.	The Transmission Operator failed to coordinate more than three new protective systems or protective system changes with neighboring Transmission Operators or Balancing Authorities or both.
R3	High	Operations Planning,	The Transmission	The Transmission	The Transmission	The Transmission

		Same-day Operations, Real-time Operations	Operator failed to coordinate protection systems on major transmission lines and interconnections with one of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	Operator failed to coordinate protection systems on major transmission lines and interconnections with two of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	Operator failed to coordinate protection systems on major transmission lines and interconnections with three of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	Operator failed to coordinate protection systems on major transmission lines and interconnections with three or more of its neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Delete data requirements as they are now handled in TOP-003-2.	Deleted Requirements 2, 5, and 6.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Note: The Project 2007-03 SDT is recommending retirement of three requirements in PRC-001-1 because those requirements address data and data requirements, which is covered in TOP-003-2. This redline shows the retired requirements, and a mapping document showing the approved requirements in PRC-001 and the proposed disposition of those requirements is posted on the Project 2007-03 page. The ballot of the conforming changes to PRC-001 is associated with the approval of TOP-003-2 and the implementation plan for this project.

More complete revisions to PRC-001 are addressed in the scope- of Project 2007-06 SDT.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
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Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that 3 requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	3Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **System Protection Coordination**
2. **Number:** PRC-001-~~1~~2
3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** ~~January 1, 2007~~ All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. *[Violation Risk factor: High]* *[Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~**R2.** Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:~~

~~**R2.1.** If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.~~

~~**R2.2.** If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.~~

~~**R3.**~~**R2.** A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

~~**R3.1.**~~**R2.1.** Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. *[Violation Risk Factor: High]* *[Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~**R3.2.**~~**R2.2.** Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High]* *][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~R4.~~R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

~~**R5.** A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:~~

~~**R5.1.** Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.~~

~~**R5.2.** Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.~~

~~**R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.~~

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements ~~3~~2, ~~3~~2.1, and ~~3~~2.2.

M2. ~~Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, documentation, electronic logs, computer printouts, or computer demonstration or other equivalent evidence that will be used to confirm that it monitors the Special Protection Systems in its area. (Requirement 6 Part 1)~~

M3. ~~Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, phone records, electronic-notifications or other equivalent evidence that will be used to confirm that it notified affected Transmission Operator and Balancing Authorities of changes in status of one of its Special Protection Systems. (Requirement 6 Part 2)~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

The Regional ~~Reliability Organizations~~ Entity shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

~~Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measures 2 and 3.~~

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.4. Compliance Monitoring and Assessment Processes

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the

preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

~~1.4.~~1.5. Additional Compliance Information

None.

2. ~~Levels of Non-Compliance for Generator Operators:~~Violation Severity Levels

~~**2.1. Level 1:** Not applicable.~~

~~**2.2. Level 2**: Not applicable.~~

~~**2.3. Level 3:** Not applicable.~~

~~**2.4. Level 4:** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority as specified in R3.1.~~

~~3. Levels of Non-Compliance for Transmission Operators:~~

~~**3.1. Level 1:** Not applicable.~~

~~**3.2. Level 2**: Not applicable.~~

~~**3.3. Level 3:** Not applicable.~~

~~**3.4. Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:~~

~~**3.4.1** Failed to provide evidence of coordination when installing new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities as specified in R3.2.~~

~~**3.4.2** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

~~4. Levels of Non-Compliance for Balancing Authorities:~~

~~**4.1. Level 1:** Not applicable.~~

~~**4.2. Level 2**: Not applicable.~~

~~**4.3. Level 3:** Not applicable.~~

~~**Level 4:** Did not monitor the status of each Special Protection System, or did not notify affected Transmission Operators, Balancing Authorities of changes in special protection status as specified in R6.~~

Reqmt. #	VRF	Time Horizon	Lower	Moderate	High	Severe
R1	High	Operations Planning, Same-day Operations, Real-time Operations	N/A	N/A	The responsible entity failed to be familiar with the limitations of protection system schemes applied in its area.	The responsible entity failed to be familiar with the purpose of protection system schemes applied in its area.
~~**R2**~~			~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity failed to notify any reliability entity of relay or equipment failures.~~
~~**R2.1**~~			~~N/A~~	~~Notification of relay or equipment failure was not made to the Transmission Operator and Host Balancing Authority, but corrective action was taken.~~	~~Notification of relay or equipment failure was made to the Transmission Operator and Host Balancing Authority, but corrective action was not taken.~~	~~Notification of relay or equipment failure was not made to the Transmission Operator and Host Balancing Authority, and corrective action was not taken.~~
~~**R2.2**~~			~~N/A~~	~~Notification of relay or equipment failure was not made to the Reliability Coordinator and affected Transmission Operators and Balancing Authorities, but corrective action was~~	~~Notification of relay or equipment failure was made to the Reliability Coordinator and affected Transmission Operators and Balancing Authorities, but corrective action was not~~	~~Notification of relay or equipment failure was not made to the Reliability Coordinator and affected Transmission Operators and Balancing Authorities, and corrective action was not~~

				~~taken.~~	~~taken.~~	~~taken.~~
R~~3~~2	N/A	N/A	N/A	N/A	N/A	N/A
R~~3~~2.1	High	Operations Planning, Same-day Operations, Real-time Operations	The Generator Operator failed to coordinate one new protective system or protective system change with either its Transmission Operator or its Host Balancing Authority or both.	The Generator Operator failed to coordinate two new protective systems or protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate three new protective systems or protective system changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate more than three new protective systems or protective system changes with its Transmission Operator or its Host Balancing Authority, or both.
R~~3~~2.2	High	Operations Planning, Same-day Operations, Real-time Operations	The Transmission Operator failed to coordinate one new protective system or protective system change with neighboring Transmission Operators or Balancing Authorities or both.	The Transmission Operator failed to coordinate two new protective systems or protective system changes with neighboring Transmission Operators or Balancing Authorities or both.	The Transmission Operator failed to coordinate three new protective systems or protective system changes with neighboring Transmission Operators or Balancing Authorities or both.	The Transmission Operator failed to coordinate more than three new protective systems or protective system changes with neighboring Transmission Operators or Balancing Authorities or both.
R~~4~~3	High	Operations Planning, Same-day Operations, Real-time Operations	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with one of its neighboring Generator	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with two of its neighboring Generator	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with three of its neighboring Generator	The Transmission Operator failed to coordinate protection systems on major transmission lines and interconnections with three or more of its neighboring

			Operators, Transmission Operators, or Balancing Authorities.	Operators, Transmission Operators, or Balancing Authorities.	Operators, Transmission Operators, or Balancing Authorities.	Generator Operators, Transmission Operators, and Balancing Authorities.
~~R5~~			~~N/A~~	~~N/A~~	~~The Generator Operator failed to notify its Transmission Operator at all of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems. (R5.1)~~ ~~OR~~ ~~The Transmission Operator failed to notify neighboring Transmission Operators at all of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems. (R5.2)~~	~~The Generator Operator failed to notify its Transmission Operator at all of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems. (R5.1)~~ ~~AND~~ ~~The Transmission Operator failed to notify neighboring Transmission Operators at all of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems. (R5.2)~~
~~R5.1~~			~~N/A~~	~~N/A~~	~~N/A~~	~~N/A~~
~~R5.2~~			~~N/A~~	~~N/A~~	~~N/A~~	~~N/A~~

~~**R6**~~			~~N/A~~	~~N/A~~	~~The responsible entity monitored the status of each Special Protection System in its area but notification of a change in status of a Special Protection System was not made to the affected Transmission Operators and Balancing Authorities.~~	~~The responsible entity failed to monitor the status of each Special Protection System in its area, and did not notify affected Transmission Operators and Balancing Authorities of each change in status.~~

~~**4.4.**~~

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Delete data requirements as they are now handled in TOP-003-2.	Deleted Requirements 2, 5, and 6.

NERC
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RELIABILITY CORPORATION

Comment Form for 7th Draft of Standards

Project 2007-03 Real-time Operations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the 7th draft and successive ballot of the standards for Real-time Operations (Project 2007-03) must be submitted by **April 20, 2012**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at (609) 947-3673.

Background Information:

This posting represents a successive ballot for TOP-001-2, TOP-002-3, and TOP-003-2.

In the 7th posting for Project 2007-03, the Real-time Operations Standard Drafting Team (RTOSDT) has attempted to clarify the proposed changes to the TOP family of standards based on industry comments received for the 6th posting and suggestions made during the Quality Review. Changes made were:

TOP-001-2:

- Requirement R1 – Allowed for plural Transmission Operators and deleted second instance of 'identified'
- Requirement R6 – changed 'the' to 'its' Reliability Coordinator
- Requirement R8 – changed 'internal area ' to 'internal to its Transmission Operator Area'; changed the Time Horizon to only Operations Planning
- Requirement R10 – changed 'each' SOL to 'an' SOL
- Data Retention – Changed voice recordings to 90 calendar days from three calendar months
- Revised VSLs for Requirements R1, R3, R5, and R10

TOP-002-3:

- Requirement R2 - changed 'internal area ' to 'internal to its Transmission Operator Area'

TOP-003-1:

- Applicability – added Distribution Provider
- Requirement R2 – added analysis functions for the Balancing Authority
- Requirement R3 – Cited the tie to Requirement R1 and made the language in Requirement R3 consistent with that in Requirement R1
- Requirement R4 - Cited the tie to Requirement R2 and made the language in Requirement R4 consistent with that in Requirement R2
- Requirement R5 – added Distribution Provider
- Measures M3 and M4 – clarified the web posting item of evidence

- Revised VSLs for Requirements R1, R2, R3,and R4

The Implementation Plan and effective dates for all three standards now show a twelve month compliance period for all requirements except Requirements R1, R2, R3, and R4 of TOP-003-2 which will become effective ten months from the approval date.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☐ No

   Comments:

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☐ No

   Comments:

3. The SDT made changes to TOP-003-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☐ No

   Comments:

4. The SDT is suggesting the retirement of three requirements in PRC-001 since those requirements deal with data handling and can now be incorporated in the data specification concept suggested for TOP-003-2. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

☐ No

Comments:

5. The VRF, VSL, and Time Horizons are part of a non-binding poll. Please indicate whether you agree or disagree with the VRF, VSL, and Time Horizon assignments. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☐ No

   Comments:

6. If you have any other comments on these standards that you have not already provided in response to the prior questions, please provide them here.

   Comments:

Resolution of Issues Assigned to Project 2007-03 Real-time Operations Standard Drafting Team

Standard	Source	Language	Resolution
TOP-001			
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started. The TOP standards have been re-written to specifically address what a Transmission Operator is responsible for. The proposed TOP requirements are no longer restricted to the undefined term 'operating emergency' and are now more inclusive and stringent than the previous requirement. Indeed, the undefined term 'operating emergency' is no longer utilized in the proposed revisions. Therefore, any delay in defining operating states in the EOP Project has no effect on the TOP standards.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may	This is covered in proposed TOP-001-2, Requirement R5.

Standard	Source	Language	Resolution
		notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	Requirement using this term was deleted as not needed in a reliability standard. The standards already require the necessary actions.
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been re-written to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-002			
TOP-002-2	FERC Order 693	1600 - Address critical energy infrastructure confidentiality as part of the routine standard development process.	Restrictions due to confidentiality have been eliminated by re-writing the data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
TOP-00-2	FERC Order 693	1601 – Require next day analysis for all IROLs to identify and communicate control actions to system operators	See proposed TOP-002-3, Requirements R1, R2, and R3.
TOP-002-2	FERC Order 693	1603 - Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-002-2	FERC Order 693	1604/1608 - Requires simulation contingencies to match what will actually happen in the field.	This is covered in proposed TOP-002-3, Requirement R1 by the phrase "and shall represent projected System conditions".
TOP-002-2	FERC Order 693	1606 - Commenters did not take issue with the proposed interpretation of the term "deliverability" as "the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches."[1] The Commission adopts this proposed	Deliverability and limits are included in Operational Planning Analysis in TOP-002-3, Requirement R1. Operational Planning Analysis contains deliverability and much more and is thus more stringent than the Order. Limit violations in the Operational Planning Analysis will show any deliverability problems regardless of type and proposed requirements mandate

[1] Id. at P 974.

Standard	Source	Language	Resolution
		interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	that these issues be resolved. In addition, the proposed requirements clearly state that an individual entity, the Transmission Operator, is wholly responsible for these concerns which is an improvement over the previous vaguely worded requirement that placed this responsibility with the Balancing Authority which has no control over the issues involved.
TOP-002-1	Fill in the Blank Team	Remove "in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements" from R6 and "in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes" from R12 .	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. Requirement R12 has been deleted as duplicative of MOD-030-2 (not yet approved).
TOP-002-2: R19	NERC Audit Observation Team	How do you address the term - verify “Accurate”	Requirement R19 was eliminated as unmeasurable.
TOP-002-2	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1.
TOP-002-1	Version 0 Team	Define N-1	Requirement R6 has been deleted.

Standard	Source	Language	Resolution
			For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. This term is no longer in use for this standard.
TOP-002-1	Version 0 Team	Define 'without intentional delay'	This term was considered unmeasurable and has been deleted from this standard.
TOP-002-1	Version 0 Team	Reliability should 'trump' confidentiality	The SDT has removed all references to confidentiality by re-writing the data specification requirements.
TOP-002-1	Version 0 Team	Coordination of planning required	The SDT has re-written and tightened up the requirements for distributing data and information.
TOP-002-1	Version 0 Team	Limit of 2 tests per year	This requirement has been deleted by the SDT as verification testing is not needed in this standard.
TOP-002-1	VRF Team	R9 – related to INT-003	Requirement R9 has been deleted as it is duplicative of approved INT-003-2
TOP-002-1	VRF Team	R14 & 14.1 – ambiguous	Deleted – duplicative of proposed TOP-003-2.
TOP-002-1	VRF Team	R2 – administrative in nature, not a real requirement	The SDT agreed and deleted this requirement.
TOP-003			
TOP-003-0	FERC Order 693	1620 & 1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability	The SDT posed a question on this issue as a fact finding exercise in the second posting of this project in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by

Standard	Source	Language	Resolution
		Standard to incorporate an appropriate lead time for planned outages.	commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. After reviewing the industry comments, the SDT concluded that proposed TOP-001-2, Requirements R5 & R6 adequately cover this issue. The SDT bases this position on the requirement which includes the Operations Planning Time Horizon that covers the period from one day to one year. The requirement mandates that actions are coordinated. The SDT interprets this to include planned outages when they are known. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	FERC Order 693	1622 - Consider TVA's suggestion for including breaker outages within the	New data specifications in proposed TOP-003-2 handle this concern.

Standard	Source	Language	Resolution
		meaning of facilities that are subject to advance notice for planned outages.	
TOP-003-0	FERC Order 693	1624 - Require any facility, that in the opinion of the reliability coordinator, balancing authority, or transmission operator, will have a direct impact on the reliability of the bulk power system be subject to the requirement R1 for planned outage coordination.	New data specifications in proposed TOP-003-2, Requirement R1 (and bullets) handle this concern.
TOP-003-0	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1
TOP-003-0	Version 0 Team	Outage information needed sooner than 1 day prior	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	Version 0 Team	RA can't request outage cancellation	Deleted – now covered in Project 2006-06.
TOP-003-0	Version 0 Team	Submit outage data ASAP but no later than noon day ahead	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	VRF Team	R4 – poorly written	Deleted – now covered in Project 2006-06.
TOP-003-1	FMPA – Frank Gaffney	With respect to requirement R1.2, why is the TOP responsible for providing generator outage information? Isn't that the BA's or GOP's responsibility and isn't this redundant with IRO-010-1?	Requirement deleted as duplicative of proposed TOP-003-2, R1.

Standard	Source	Language	Resolution
TOP-004			
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	Replaced by proposed TOP-001-2, R7 through R11. T_v is more stringent than the existing 30 minute requirement for IROLs and 30 minutes is retained for selected SOLs. Unknown states, in this context, cannot exist because valid operating limits have been determined for all Facilities in a TOP's footprint. The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to Emergencies.
TOP-004-1	FERC Order 693	1637 - Reliability coordinators should report any IROL violations to NERC on a monthly basis for one year beginning August 2, 2007.	Not within the scope of the SDT.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (. . .the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or	The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the bulk power system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under . . . high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	FERC Order 693	1639 - Consider Santa Clara's comments regarding changes to requirement R2 in the standards development process. (Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.)	This is covered as part of the new data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by proposed IRO-010-1, Requirement R3.
TOP-004-1	FERC Order 693	1641 - NERC should report the results of the survey to the Commission within 18 months	Not within the scope of the SDT.

Standard	Source	Language	Resolution
		of the effective date of this rule.	
TOP-004-1	Fill in the Blank Team	No action required	No action required.
TOP-004-1	Version 0 Team	Operations should conform to planning standards	Operations and planning are different timeframes with different problems and solutions
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	Requirement moved to proposed TOP-001-2, Requirement R5 and clarified.
TOP-004-1	Version 0 Team	Define SOL & IROL	These are defined terms in the NERC Glossary.
TOP-004-1	Version 0 Team	Clarify roles	Applicability has been reviewed and updated as necessary.
TOP-004-1	Version 0 Team	Define (or remove) practical	The term has been removed.
TOP-004-1	Version 0 Team	Specify disconnection as acceptable in R5	The requirement has been deleted. Relationships between the Reliability Coordinator and Transmission Operator as described in the revised standards cover these actions.
TOP-005			
TOP-005-1	FERC Order 693	1648 - Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.
TOP-005-1	FERC Order 693	1649 - Delete references to confidentiality agreements but ensure critical energy infrastructure confidentiality is addressed in the standards development process.	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	FERC Order 693	1650 - Consider FirstEnergy’s modifications to Attachment 1 and ISO-NE’s recommended revision to requirement R4 in the standards	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.

Standard	Source	Language	Resolution
		development process. ISO-NE recommends that the reference to "purchasing-selling entity" in Requirement R4 should be replaced with "generator owner, transmission owner, and LSE.	Requirement R4 has been superseded by proposed TOP-003-2 which does include the indicated entities.
TOP-005-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R2 of PRC-001-1 in TOP-005. Note: These requirements are being removed from PRC.	See proposed TOP-003-2, Requirement R1
TOP-005-1	Version 0 Team	Need to include GO & LSE	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Data update is too slow	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Generator data should include voltage control & stabilizers	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	GO needs to supply data to BA & TO	New data specifications in proposed TOP-003-2 handle this concern
TOP-005-1	Received for the November 4, 2009 Technical Conference on Interpretations of Standards	NERC staff believes that the interpretation does not support the stated purpose of IRO-005-1: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The	While this issue was entered against the Transmission Operator as the interpretation request was primarily for TOP-005-1, the emphasis on such informative actions has shifted in current revision projects. The proposed IRO-010-1, Requirement R1 gives the Reliability Coordinator the right to ask for any reliability related data that they need to perform their Reliability Coordinator task.

Standard	Source	Language	Resolution
	from Manitoba Hydro	Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas." Given that Requirement R12 pre-supposes that the SPS is armed to address inter-Balancing Authority or inter-Transmission Operator impacts (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), the argument not discussed in the interpretation is that the SPS itself with one communication channel in service can be viewed for advance planning or reliability assessment purposes as a single contingency (loss of the communication channel). The question asked by the requestor indicates that the operation of the SPS on a single channel is known ahead of the timeframe for which the SPS may be armed and that the condition was not first identified when the SPS was called to operate. In this regard, the Reliability Coordinator must be aware of the less dependable state of the SPS in order to properly assess the impact and plan for the next single contingency that it conceivably could	And it also mandates the Transmission Operator to provide said data in Requirement R3. (Note – This standard has been approved by the BOT but has not yet been approved by FERC.)

Standard	Source	Language	Resolution
		experience. In this case, the Reliability Coordinator may wish to consider the loss of an armed SPS when performing its reliability assessments. While the Reliability Coordinator may not elect to proactively position the system to withstand the loss of the SPS that is operating on a single communication channel, the Reliability Coordinator may elect to develop a contingency plan in the event the SPS does fail to operate as designed or if the remaining communication channel is lost. The importance of the SPS relative to current or anticipated system conditions would be considerations for the Reliability Coordinator. This consideration only becomes possible if the Transmission Operator notifies the Reliability Coordinator that the SPS is operating on a single communication channel. Therefore, Transmission Operator notification to the Reliability Coordinator of this condition raises the Reliability Coordinator's situational awareness that may influence current or future operating conditions or decisions in a preventive rather than reactive manner. NERC staff does agree that the SPS	

Standard	Source	Language	Resolution
		is still mission capable with only one communication channel in service, but degraded in terms of its dependability due to the unavailability of redundant communications channels. The fact that a second communications channel was part of the original design of the SPS suggests that both channels were important to the dependability of the system, and that the unavailability of either channel causes some degradation in the overall dependability of the SPS. Additionally, the team equated “any degradation” with “potential failure to operate as expected” in IRO-005. The use of the term “or” connecting these two phrases in the standard indicates these were not intended to be equivalent. Therefore, NERC staff believes the conclusion reached by the team that the two terms are synonymous is incorrect. Further, the specific circumstances contemplated in the interpretation request are not likely to occur often and the additional burden to Transmission Operators to notify the Reliability Coordinator is de minimis when compared to the improved situational awareness that would result. On	

Standard	Source	Language	Resolution
		this basis, NERC staff believes the interpretation is not serving the best interests of reliability and should be remanded to the team for further consideration of the NERC staff opinion.	
TOP-006			
TOP-006-1	FERC Order 693	1660 & 1661 - Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system.	Minimum capabilities for Transmission Operators are being handled in project 2009-02, Real-time Monitoring and Analysis Capabilities. Requirement for phase angle information is covered by proposed TOP-003-2.
TOP-006-1	FERC Order 693	1663 - Clarify the meaning of “appropriate technical information” concerning protective relays. To provide more clarity, criteria that define what “appropriate technical information” is necessary should be specified so that operators can make better informed decisions.	This term is no longer used. Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and TOP-003-2 (data).
TOP-006-1	FERC Order 693	1664 - Consider APPA’s comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
TOP-006-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards.	See proposed TOP-003-2, Requirement R1

Standard	Source	Language	Resolution
		Consider putting R6 of PRC-001-1 in TOP-003 R5 or TOP-006. Note: These requirements are being retired in PRC-001-1.	
TOP-006-1	Version 0 Team	Need to match roles with FM	Applicability has been reviewed by the SDT and changed as required in accordance with the FM and the Compliance Registry.
TOP-006-1	Version 0 Team	Monitor frequency at multiple points	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	Load forecasting data required	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	GO needs to provide normal & emergency data	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R1, 1.1, 1.2 – 'available in emergency situation' may be needed	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R3 – define appropriate	This requirement was deleted as duplicative of approved PRC-001-1, Requirement R1.
TOP-006-1	VRFs Team	R4 – What information is required and what is a load pattern?	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirements R1 and R1.2, why are BAs responsible for information regarding transmission resources available for use? Isn't that the role of the TOP?	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R2, why is the BA responsible for monitoring transmission line status, voltage, load tap changer settings, and reactive power in general?	Deleted – SDT agrees.

Standard	Source	Language	Resolution
		Monitoring and managing reactive resources, voltage and tap settings is clearly made the responsibility of the TOP in VAR-001-1a.	
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R3 why does the BA need to understand protective relaying? Isn't that the role of the TOP and GOP?	Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and proposed TOP-003-2 (data).
TOP-007			
TOP-007-0	FERC Order 693	1673 - Consider the NRC's comments on voltage requirements as part of the standards development process.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-007-0	Version 0 Team	Need to define evidence of evaluation	This term isn't used in the requirements – no action required.
TOP-007-0	Version 0 Team	Need to tighten the non-compliance terms	Measures and VSL have been assigned to all requirements.
TOP-007-0	Version 0 Team	Not enforceable with current criteria	Not enough information provided to address concern.
TOP-007-0	Version 0 Team	RA should be included	Reliability Coordinator is now covered in Project 2006-06.

Standard	Source	Language	Resolution
TOP-007-0	Version 0 Team	More of a compliance issue than a true standard	Not enough information provided to address concern.
		TOP-008	
TOP-008-1	FERC Order 693	1681 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
		PER-001	
PER-001-0	Version 0 Team	Data retention should be 1 year	This standard will be retired.
		Transferred from Project	
PRC-001	Project 2007-06	1441- S- Ref 10339 - Clarify the term corrective action. 1440. We believe that [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System. 1441. We direct the ERO to clarify the term corrective action consistent with this discussion when it modifies PRC-001-1 in the Reliability Standards development process.	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations.
PRC-001	Project 2007-06	1444 - S- Ref 10340 - Consider First Energy and the California PUCs comments about the	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations. The

Standard	Source	Language	Resolution
		maximum time for corrective actions in the standards development process. 1428. California PUC contends that imposing a time restriction for returning a system to a stable state may cause more harm than good since additional information and options may be available as time elapses. It repeats its suggestion from its earlier comments on the Staff Preliminary Assessment and proposes the following alternative language: Transmission or generation operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible, and no longer than 30 minutes, except where a longer response time is feasible, or where a longer response is demonstrated to produce a better ultimate solution without unacceptable interim risk. 1431. FirstEnergy contends that Requirement R2.1 essentially requires generator operators to report all protective relay or equipment failures, since generator operators may not be able to tell which failures will reduce system reliability. FirstEnergy suggests that R2.1 should be	Transmission Operator is the true functional entity responsible here. Covered as part of the new data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
		revised to require generator operators to report all equipment failures or outages. FirstEnergy further suggests that PRC-001-1 be revised to provide that if a company performs reasonable testing procedures, undiscoverable equipment failures will not be violations of R2.1	
PRC-001	Project 2007-06	1449 - S- Ref 10341 - Upon detection of failures in relays or protection system elements on the bulk power system that threaten reliability, relevant transmission operators must be informed promptly, but within a specified period of time. -- (2) a requirement that transmission and generator operators be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities could carry out appropriate corrective control actions consistent with those used in mitigating IROL violations.	Covered as part of the new data specification requirements in proposed TOP-003-2.
PRC-001	Project 2007-06	1449 - S- Ref 10343 - Para 1420. Once informed, transmission operators must carry out corrective control actions that return the system to a stable state that respects system requirements as soon as possible and no	Covered in TOP-001-2, Requirement R11.

Standard	Source	Language	Resolution
		longer than 30 minutes. 1440. [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.	

Resolution of Issues Assigned to Project 2007-03 Real-time Operations ~~SDT (Project 2007-03)~~Standard Drafting Team

Standard	Source	Language	Resolution
TOP-001			
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started. The TOP standards have been re-written to specifically address what a Transmission Operator is responsible for. The proposed TOP requirements are no longer restricted to the undefined term 'operating emergency' and are now more inclusive and stringent than the previous requirement. Indeed, the undefined term 'operating emergency' is no longer utilized in the proposed revisions. Therefore, any delay in defining operating states in the EOP Project has no effect on the TOP standards.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may	This is covered in proposed TOP-001-2, Requirement R5.

Standard	Source	Language	Resolution
		notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	Requirement using this term was deleted as not needed in a reliability standard. The standards already require the necessary actions.
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been re-written to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-002			
TOP-002-2	FERC Order 693	1600 - Address critical energy infrastructure confidentiality as part of the routine standard development process.	Restrictions due to confidentiality have been eliminated by re-writing the data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
TOP-00-2	FERC Order 693	1601 – Require next day analysis for all IROLs to identify and communicate control actions to system operators	See proposed TOP-002-3, Requirements R1, R2, and R3.
TOP-002-2	FERC Order 693	1603 - Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-002-2	FERC Order 693	1604/1608 - Requires simulation contingencies to match what will actually happen in the field.	This is covered in proposed TOP-002-3, Requirement R1 by the phrase ~~“…~~“and shall represent projected System conditions”.
TOP-002-2	FERC Order 693	1606 - Commenters did not take issue with the proposed interpretation of the term “deliverability” as “the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches.”[1] The Commission adopts this proposed	Deliverability and limits are included in Operational Planning Analysis in TOP-002-3, Requirement R1. Operational Planning Analysis contains deliverability and much more and is thus more stringent than the Order. Limit violations in the Operational Planning Analysis will show any deliverability problems regardless of type and proposed requirements mandate

[1] Id. at P 974.

Standard	Source	Language	Resolution
		interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	that these issues be resolved. In addition, the proposed requirements clearly state that an individual entity, the Transmission Operator, is wholly responsible for these concerns which is an improvement over the previous vaguely worded requirement that placed this responsibility with the Balancing Authority which has no control over the issues involved.
TOP-002-1	Fill in the Blank Team	Remove "in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements" from R6 and "in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes" from R12 .	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. Requirement R12 has been deleted as duplicative of MOD-030-2 (not yet approved).
TOP-002-2: R19	NERC Audit Observation Team	How do you address the term - verify "Accurate"	Requirement R19 was eliminated as unmeasurable.
TOP-002-2	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1.
TOP-002-1	Version 0 Team	Define N-1	Requirement R6 has been deleted.

Standard	Source	Language	Resolution
			For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. This term is no longer in use for this standard.
TOP-002-1	Version 0 Team	Define 'without intentional delay'	This term was considered unmeasurable and has been deleted from this standard.
TOP-002-1	Version 0 Team	Reliability should 'trump' confidentiality	The SDT has removed all references to confidentiality by re-writing the data specification requirements.
TOP-002-1	Version 0 Team	Coordination of planning required	The SDT has re-written and tightened up the requirements for distributing data and information.
TOP-002-1	Version 0 Team	Limit of 2 tests per year	This requirement has been deleted by the SDT as verification testing is not needed in this standard.
TOP-002-1	VRF Team	R9 – related to INT-003	Requirement R9 has been deleted as it is duplicative of approved INT-003-2
TOP-002-1	VRF Team	R14 & 14.1 – ambiguous	Deleted – duplicative of proposed TOP-003-2.
TOP-002-1	VRF Team	R2 – administrative in nature, not a real requirement	The SDT agreed and deleted this requirement.
TOP-003			
TOP-003-0	FERC Order 693	1620 & 1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability	The SDT posed a question on this issue as a fact finding exercise in the second posting of this project in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by

Standard	Source	Language	Resolution
		Standard to incorporate an appropriate lead time for planned outages.	commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. After reviewing the industry comments, the SDT concluded that proposed TOP-001-2, Requirements R5 & R6 adequately cover this issue. The SDT bases this position on the requirement which includes the Operations Planning Time Horizon that covers the period from one day to one year. The requirement mandates that actions are coordinated. The SDT interprets this to include planned outages when they are known. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	FERC Order 693	1622 - Consider TVA's suggestion for including breaker outages within the	New data specifications in proposed TOP-003-2 handle this concern.

Standard	Source	Language	Resolution
		meaning of facilities that are subject to advance notice for planned outages.	
TOP-003-0	FERC Order 693	1624 - Require any facility, that in the opinion of the reliability coordinator, balancing authority, or transmission operator, will have a direct impact on the reliability of the bulk power system be subject to the requirement R1 for planned outage coordination.	New data specifications in proposed TOP-003-2, Requirement R1 (and bullets) handle this concern.
TOP-003-0	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1
TOP-003-0	Version 0 Team	Outage information needed sooner than 1 day prior	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	Version 0 Team	RA can’t request outage cancellation	Deleted – now covered in Project 2006-06.
TOP-003-0	Version 0 Team	Submit outage data ASAP but no later than noon day ahead	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	VRF Team	R4 – poorly written	Deleted – now covered in Project 2006-06.
TOP-003-1	FMPA – Frank Gaffney	With respect to requirement R1.2, why is the TOP responsible for providing generator outage information? Isn't that the BA's or GOP's responsibility and isn't this redundant with IRO-010-1?	Requirement deleted as duplicative of proposed TOP-003-2, R1.

Standard	Source	Language	Resolution
TOP-004			
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	Replaced by proposed TOP-001-2, R7 through R11. T_v is more stringent than the existing 30 minute requirement for IROLs and 30 minutes is retained for selected SOLs. Unknown states, in this context, cannot exist because valid operating limits have been determined for all Facilities in a TOP's footprint. The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to Emergencies.
TOP-004-1	FERC Order 693	1637 - Reliability coordinators should report any IROL violations to NERC on a monthly basis for one year beginning August 2, 2007.	Not within the scope of the SDT.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (. . .the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or	The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the bulk power system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under . . . high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	FERC Order 693	1639 - Consider Santa Clara's comments regarding changes to requirement R2 in the standards development process. (Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.)	This is covered as part of the new data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by proposed IRO-010-1, Requirement R3.
TOP-004-1	FERC Order 693	1641 - NERC should report the results of the survey to the Commission within 18 months	Not within the scope of the SDT.

Standard	Source	Language	Resolution
		of the effective date of this rule.	
TOP-004-1	Fill in the Blank Team	No action required	No action required.
TOP-004-1	Version 0 Team	Operations should conform to planning standards	Operations and planning are different timeframes with different problems and solutions
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	Requirement moved to proposed TOP-001-2, Requirement R5 and clarified.
TOP-004-1	Version 0 Team	Define SOL & IROL	These are defined terms in the NERC Glossary.
TOP-004-1	Version 0 Team	Clarify roles	Applicability has been reviewed and updated as necessary.
TOP-004-1	Version 0 Team	Define (or remove) practical	The term has been removed.
TOP-004-1	Version 0 Team	Specify disconnection as acceptable in R5	The requirement has been deleted. Relationships between the Reliability Coordinator and Transmission Operator as described in the revised standards cover these actions.
TOP-005			
TOP-005-1	FERC Order 693	1648 - Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.
TOP-005-1	FERC Order 693	1649 - Delete references to confidentiality agreements but ensure critical energy infrastructure confidentiality is addressed in the standards development process.	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	FERC Order 693	1650 - Consider FirstEnergy's modifications to Attachment 1 and ISO-NE's recommended revision to requirement R4 in the standards	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.

Standard	Source	Language	Resolution
		development process. ISO-NE recommends that the reference to "purchasing-selling entity" in Requirement R4 should be replaced with "generator owner, transmission owner, and LSE.	Requirement R4 has been superseded by proposed TOP-003-2 which does include the indicated entities.
TOP-005-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R2 of PRC-001-1 in TOP-005. Note: These requirements are being removed from PRC.	See proposed TOP-003-2, Requirement R1
TOP-005-1	Version 0 Team	Need to include GO & LSE	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Data update is too slow	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Generator data should include voltage control & stabilizers	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	GO needs to supply data to BA & TO	New data specifications in proposed TOP-003-2 handle this concern
TOP-005-1	Received for the November 4, 2009 Technical Conference on Interpretations of Standards	NERC staff believes that the interpretation does not support the stated purpose of IRO-005-1: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The	While this issue was entered against the Transmission Operator as the interpretation request was primarily for TOP-005-1, the emphasis on such informative actions has shifted in current revision projects. The proposed IRO-010-1, Requirement R1 gives the Reliability Coordinator the right to ask for any reliability related data that they need to perform their Reliability Coordinator task.

Standard	Source	Language	Resolution
	from Manitoba Hydro	Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas." Given that Requirement R12 pre-supposes that the SPS is armed to address inter-Balancing Authority or inter-Transmission Operator impacts (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), the argument not discussed in the interpretation is that the SPS itself with one communication channel in service can be viewed for advance planning or reliability assessment purposes as a single contingency (loss of the communication channel). The question asked by the requestor indicates that the operation of the SPS on a single channel is known ahead of the timeframe for which the SPS may be armed and that the condition was not first identified when the SPS was called to operate. In this regard, the Reliability Coordinator must be aware of the less dependable state of the SPS in order to properly assess the impact and plan for the next single contingency that it conceivably could	And it also mandates the Transmission Operator to provide said data in Requirement R3. (Note – This standard has been approved by the BOT but has not yet been approved by FERC.)

Standard	Source	Language	Resolution
		experience. In this case, the Reliability Coordinator may wish to consider the loss of an armed SPS when performing its reliability assessments. While the Reliability Coordinator may not elect to proactively position the system to withstand the loss of the SPS that is operating on a single communication channel, the Reliability Coordinator may elect to develop a contingency plan in the event the SPS does fail to operate as designed or if the remaining communication channel is lost. The importance of the SPS relative to current or anticipated system conditions would be considerations for the Reliability Coordinator. This consideration only becomes possible if the Transmission Operator notifies the Reliability Coordinator that the SPS is operating on a single communication channel. Therefore, Transmission Operator notification to the Reliability Coordinator of this condition raises the Reliability Coordinator's situational awareness that may influence current or future operating conditions or decisions in a preventive rather than reactive manner. NERC staff does agree that the SPS	

Standard	Source	Language	Resolution
		is still mission capable with only one communication channel in service, but degraded in terms of its dependability due to the unavailability of redundant communications channels. The fact that a second communications channel was part of the original design of the SPS suggests that both channels were important to the dependability of the system, and that the unavailability of either channel causes some degradation in the overall dependability of the SPS. Additionally, the team equated "any degradation" with "potential failure to operate as expected" in IRO-005. The use of the term "or" connecting these two phrases in the standard indicates these were not intended to be equivalent. Therefore, NERC staff believes the conclusion reached by the team that the two terms are synonymous is incorrect. Further, the specific circumstances contemplated in the interpretation request are not likely to occur often and the additional burden to Transmission Operators to notify the Reliability Coordinator is de minimis when compared to the improved situational awareness that would result. On	

Standard	Source	Language	Resolution
		this basis, NERC staff believes the interpretation is not serving the best interests of reliability and should be remanded to the team for further consideration of the NERC staff opinion.	
TOP-006			
TOP-006-1	FERC Order 693	1660 & 1661 - Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system.	Minimum capabilities for Transmission Operators are being handled in project 2009-02, Real-time Monitoring and Analysis Capabilities. Requirement for phase angle information is covered by proposed TOP-003-2.
TOP-006-1	FERC Order 693	1663 - Clarify the meaning of "appropriate technical information" concerning protective relays. To provide more clarity, criteria that define what "appropriate technical information" is necessary should be specified so that operators can make better informed decisions.	This term is no longer used. Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and TOP-003-2 (data).
TOP-006-1	FERC Order 693	1664 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
TOP-006-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards.	See proposed TOP-003-2, Requirement R1

Standard	Source	Language	Resolution
		Consider putting R6 of PRC-001-1 in TOP-003 R5 or TOP-006. Note: These requirements are being retired in PRC-001-1.	
TOP-006-1	Version 0 Team	Need to match roles with FM	Applicability has been reviewed by the SDT and changed as required in accordance with the FM and the Compliance Registry.
TOP-006-1	Version 0 Team	Monitor frequency at multiple points	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	Load forecasting data required	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	GO needs to provide normal & emergency data	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R1, 1.1, 1.2 – 'available in emergency situation' may be needed	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R3 – define appropriate	This requirement was deleted as duplicative of approved PRC-001-1, Requirement R1.
TOP-006-1	VRFs Team	R4 – What information is required and what is a load pattern?	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirements R1 and R1.2, why are BAs responsible for information regarding transmission resources available for use? Isn't that the role of the TOP?	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R2, why is the BA responsible for monitoring transmission line status, voltage, load tap changer settings, and reactive power in general?	Deleted – SDT agrees.

Standard	Source	Language	Resolution
		Monitoring and managing reactive resources, voltage and tap settings is clearly made the responsibility of the TOP in VAR-001-1a.	
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R3 why does the BA need to understand protective relaying? Isn't that the role of the TOP and GOP?	Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and proposed TOP-003-2 (data).
TOP-007			
TOP-007-0	FERC Order 693	1673 - Consider the NRC's comments on voltage requirements as part of the standards development process.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-007-0	Version 0 Team	Need to define evidence of evaluation	This term isn't used in the requirements – no action required.
TOP-007-0	Version 0 Team	Need to tighten the non-compliance terms	Measures and VSL have been assigned to all requirements.
TOP-007-0	Version 0 Team	Not enforceable with current criteria	Not enough information provided to address concern.
TOP-007-0	Version 0 Team	RA should be included	Reliability Coordinator is now covered in Project 2006-06.

Standard	Source	Language	Resolution
TOP-007-0	Version 0 Team	More of a compliance issue than a true standard	Not enough information provided to address concern.
		TOP-008	
TOP-008-1	FERC Order 693	1681 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
		PER-001	
PER-001-0	Version 0 Team	Data retention should be 1 year	This standard will be retired.
		Transferred from Project	
PRC-001	Project 2007-06	1441- S- Ref 10339 - Clarify the term corrective action. 1440. We believe that [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System. 1441. We direct the ERO to clarify the term corrective action consistent with this discussion when it modifies PRC-001-1 in the Reliability Standards development process.	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations.
PRC-001	Project 2007-06	1444 - S- Ref 10340 - Consider First Energy and the California PUCs comments about the	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations. The

Standard	Source	Language	Resolution
		maximum time for corrective actions in the standards development process. 1428. California PUC contends that imposing a time restriction for returning a system to a stable state may cause more harm than good since additional information and options may be available as time elapses. It repeats its suggestion from its earlier comments on the Staff Preliminary Assessment and proposes the following alternative language: Transmission or generation operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible, and no longer than 30 minutes, except where a longer response time is feasible, or where a longer response is demonstrated to produce a better ultimate solution without unacceptable interim risk. 1431. FirstEnergy contends that Requirement R2.1 essentially requires generator operators to report all protective relay or equipment failures, since generator operators may not be able to tell which failures will reduce system reliability. FirstEnergy suggests that R2.1 should be	Transmission Operator is the true functional entity responsible here. Covered as part of the new data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
		revised to require generator operators to report all equipment failures or outages. FirstEnergy further suggests that PRC-001-1 be revised to provide that if a company performs reasonable testing procedures, undiscoverable equipment failures will not be violations of R2.1	
PRC-001	Project 2007-06	1449 - S- Ref 10341 - Upon detection of failures in relays or protection system elements on the bulk power system that threaten reliability, relevant transmission operators must be informed promptly, but within a specified period of time. -- (2) a requirement that transmission and generator operators be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities could carry out appropriate corrective control actions consistent with those used in mitigating IROL violations.	Covered as part of the new data specification requirements in proposed TOP-003-2.
PRC-001	Project 2007-06	1449 - S- Ref 10343 - Para 1420. Once informed, transmission operators must carry out corrective control actions that return the system to a stable state that respects system requirements as soon as possible and no	Covered in TOP-001-2, Requirement R11.

Standard	Source	Language	Resolution
		longer than 30 minutes. 1440. [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.	

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-03 Real-time Operations

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001-2 – Transmission Operations, TOP-002-3 – Operations Planning, and TOP-003-2 – Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in TOP-001-2, TOP-002-3, TOP-003-2:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Eemergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the bulk power system.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the bulk power system:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eleven requirements in TOP-001-2. None of the eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, R4, R7, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1.1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Not informing a Transmission Operator of the inability to perform a Reliability Directive could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render Emergency assistance could lead to bulk power system instability, separation or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or Cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R6 has been assigned a Medium VRF and is the replacement for proposed TOP-003-1, Requirement R3 which was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system, regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or Cascading failures

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to operating within the IROL.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R7 mandates that entities operate within each identified IROL and its associated IROL T_v. By definition, if an entity fails to do so, bulk power system instability, separation, or Cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R8 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or Cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R9 mandates that entities operate within each identified local SOL. Since local SOLs in Requirement R9, by definition, can't cause bulk power system instability, separation, or Cascading this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, Requirements R7 and R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, Requirements R7, R9, and R11 and this requirement is a simple notification requirement for informational purposes only. Therefore, bulk power system instability, separation, or Cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. It is also

similar to proposed TOP-001-2, Requirement R7 which has been assigned a High VRF. Therefore, there is consistency among Reliability Standards.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities act or direct others to act to mitigate the magnitude and duration of exceeding an IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or Cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-3, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved IRO-001-1.1, Requirement R8. That VSL has a Moderate violation for not complying with the Reliability Coordinator's directive for a valid reason but not informing the Reliability Coordinator of this fact. It then goes on to establish a Severe VSL for not complying with the directive. The SDT found little reason to separate out a Moderate VSL for not informing	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		the Transmission Operator. Whether it was for a valid reason or not, the consequences of the Transmission Operator not being aware of the fact that the directive was not being followed are potentially catastrophic. Therefore, the SDT has proposed only a Severe VSL and this VSL I more stringent than the VSL cited. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1.1a, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-004-2, Requirement R1. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		Therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-03 Real-time Operations

Violation Risk Factor and Violation Severity Level Assignments
This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001-2 – Transmission Operations, TOP-002-3 – Operations Planning, and TOP-003-2 – Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in TOP-001-2, TOP-002-3, TOP-003-2:
The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement
A requirement that, if violated, could directly cause or contribute to ~~bulk~~ Bulk ~~electric~~ Electric ~~system~~ System instability, separation, or a ~~cascading~~ Cascading sequence of failures, or could place the ~~bulk electric system~~Bulk Electric System at an unacceptable risk of instability, separation, or ~~cascading~~ Cascading failures; or, a requirement in a planning time frame that, if violated, could, under ~~emergency~~Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to ~~bulk electric system~~Bulk Electric System instability, separation, or a ~~cascading~~ Cascading sequence of failures, or could place the ~~bulk electric system~~Bulk Electric System at an unacceptable risk of instability, separation, or ~~cascading~~ Cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement
A requirement that, if violated, could directly affect the electrical state or the capability of the ~~bulk electric system~~Bulk Electric System, or the ability to effectively monitor and control the ~~bulk electric system~~Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to ~~bulk electric system~~Bulk Electric System instability, separation, or ~~cascading~~ Cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System, or the ability to effectively monitor, control, or restore the ~~bulk electric system~~Bulk Electric System. However, violation of a medium risk requirement is unlikely, under ~~emergency~~Emergency, abnormal, or restoration conditions anticipated

by the preparations, to lead to ~~bulk electric system~~Bulk Electric System instability, separation, or ~~cascading~~ Cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System, or the ability to effectively monitor and control the ~~bulk electric system~~Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Eemergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System, or the ability to effectively monitor, control, or restore the ~~bulk electric system~~Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the ~~Bulk-Power System~~bulk power system.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the ~~Bulk-Power System~~bulk power system:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

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[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").

[2] Id. at footnote 15.

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eleven requirements in TOP-001-2. None of the eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, R4, R7, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. Therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1.1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Not informing~~-~~ a Transmission Operator of the inability to perform ~~A~~a Reliability Directive could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or ~~cascading~~ Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render ~~emergency~~ Emergency assistance could lead to bulk power system instability, separation or ~~cascading~~ Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or ~~cascading~~ Cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R6 has been assigned a Medium VRF and is the replacement~~-~~ for proposed TOP-003-1, Requirement R3 which was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. The applicable entities are always responsible for maintaining the

reliability of the bulk power system, regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or ~~cascading~~ Cascading failures

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to operating within the IROL.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R7 mandates that entities operate within each identified IROL and its associated IROL T_V. By definition, if an entity fails to do so, bulk power system instability, separation, or ~~cascading~~ Cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- ~~Bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.~~ FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R8 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R9 mandates that entities operate within each identified local SOL. Since local SOLs in Requirement R9, by definition, can't cause bulk power system instability, separation, or ~~cascading~~ Cascading this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, Requirements R7 and R9~~ which have High VRFs~~. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, Requirements R7, R9, and R11 and this requirement is a simple notification requirement for informational purposes only. Therefore, bulk power system instability, separation, or ~~cascading~~ Cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. It is also similar to proposed TOP-001-2, Requirement R7 which has been assigned a High VRF. Therefore, there is consistency among Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities act or direct others to act to mitigate the magnitude and duration of exceeding an IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or ~~cascading~~ Cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-3, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved IRO-001-1.1, Requirement R8. That VSL has a Moderate violation for not complying with the Reliability Coordinator's directive for a valid reason but not informing the Reliability Coordinator of this fact. It then goes on to establish a Severe VSL for not complying with the directive. The SDT found little reason to separate out a Moderate VSL for not informing	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		the Transmission Operator. Whether it was for a valid reason or not, the consequences of the Transmission Operator not being aware of the fact that the directive was not being followed are potentially catastrophic. Therefore, the SDT has proposed only a Severe VSL and this VSL I ~~s~~ more stringent than the VSL cited. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1.1a, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-004-2, Requirement R1. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		Therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

A. Introduction

1. **Title:** **Operating Personnel Responsibility and Authority**

2. **Number:** PER-001-0.1

3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** December 10, 2009

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The job description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. **Compliance Monitoring Process**

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0.1	April 15, 2009	Replaced “position” with “job” on M1.1	Errata
0.1	December 10, 2009	Approved by FERC — added effective date	Update

A. Introduction

1. **Title:** **Reliability Responsibilities and Authorities**

2. **Number:** TOP-001-1

Purpose: To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

3. **Applicability**

3.1. Balancing Authorities

3.2. Transmission Operators

3.3. Generator Operators

3.4. Distribution Providers

3.5. Load Serving Entities

4. **Effective Date:** January 1, 2007

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:

R7.1. For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.2. For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.3. When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

C. Measures

M1. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.

M2. If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)

M3. Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)

M4. Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or

statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)

M5. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

M6. The Transmission Operator, Balancing Authority, and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)

M7. The Transmission Operator and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Balancing Authority:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

2.4.2 Did not render emergency assistance to others as requested, in accordance with R6.

3. Levels of Non-Compliance for a Transmission Operator

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Does not have the documented authority to act as specified in R1.

3.4.2 Does not have evidence it acted with the authority specified in R1.

3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.

3.4.4 Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.

3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.

3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.

3.4.7 Did not render emergency assistance to others as requested, as specified in R6.

3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

4. Levels of Non-Compliance for a Generator Operator:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.

4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.

4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity

5.1. Level 1: Not applicable.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable

5.4. Level 4: Did not comply with a Transmission Operator's reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Normal Operations Planning**
2. **Number:** TOP-002-2a
3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
4. **Applicability**
   - **4.1.** Balancing Authority.
   - **4.2.** Transmission Operator.
   - **4.3.** Generator Operator.
   - **4.4.** Load Serving Entity.
   - **4.5.** Transmission Service Provider.
5. **Effective Date:** Immediately after approval of applicable regulatory authorities. FERC Approved 12/2/09

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)

R14.1. Changes in real output capabilities. (Effective August 1, 2007)

R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance for Balancing Authorities:**

   2.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

   2.2. **Level 2:** Not applicable.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4**: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

      2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. **Levels of Non-Compliance for Transmission Operators**

   3.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

   3.2. **Level 2:** Not applicable.

   3.3. **Level 3:** One or more of Bulk Electric System studies were not made available as specified in R11.

   3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

      3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

      3.4.3 Studies not updated to reflect current system conditions as specified in R11.

      3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. **Levels of Non-Compliance for Generator Operators:**

   4.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

   4.2. **Level 2:** Not applicable.

   4.3. **Level 3:** Not applicable.

   4.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

      4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

      4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. **Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:**

   5.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation

Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a "unique" study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have "a" study that can be applied to it, but it is not necessary to generate a "unique" study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a "study"? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, "to determine SOLs" as used in the first sentence of Requirement R11 mean the "determination of system operating limits" or does it mean the "identification of potential SOL violations?"

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential "exceedances" of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.

A. Introduction

1. **Title:** **Planned Outage Coordination**

2. **Number:** TOP-003-1

3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.

4. **Applicability**

   4.1. Generator Operators.

   4.2. Transmission Operators.

   4.3. Balancing Authorities.

   4.4. Reliability Coordinators.

5. **Proposed Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information.

R1.1. Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.

R1.2. Each Transmission Operator shall provide outage information daily to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.

R1.3. Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, and Balancing Authority reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to "not be taken" because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Generator Operator failed to provide outage information, in accordance with its Transmission Operators established outage reporting requirements, to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW).
R1.1	N/A	N/A	N/A	The Transmission Operator failed to provide outage information, in accordance with its Reliability Coordinators established outage reporting requirement, to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.
R1.2	The responsible entity failed to provide the information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	N/A	N/A	N/A

R#	Lower	Moderate	High	Severe
R1.3	N/A	N/A	N/A	The responsible entity failed to plan or coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators when required.
R2	The responsible entity planned and coordinated scheduled outages of telemetering and control equipment and associated communication channels with its Reliability Coordinator, but failed to coordinate with affected neighboring Transmission Operators, Balancing Authorities, and Generator Operators.	N/A	N/A	The responsible entity failed to plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
R3	N/A	N/A	N/A	The Reliability Coordinator failed to resolve any scheduling of potential reliability conflicts.
R4	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 30 minutes but less than or equal to 35 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 35 minutes but less than or equal to 40 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 40 minutes but less than or equal to 45 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 45 minutes.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 23, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	

A. Introduction

1. **Title:** **Transmission Operations**

2. **Number:** TOP-004-2

3. **Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.

4. **Applicability:**

   4.1. Transmission Operators

5. **Proposed Effective Date:** Twelve months after BOT adoption of FAC-014.

B. Requirements

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.

R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.

R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

R6.1. Monitoring and controlling voltage levels and real and reactive power flows.

R6.2. Switching transmission elements.

R6.3. Planned outages of transmission elements.

R6.4. Responding to IROL and SOL violations.

C. Measures

M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.

M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data for Measure 1.

Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.

2.3. .**Level 3:** Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.

2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata

A. Introduction

1. **Title:** **Operational Reliability Information**

2. **Number:** TOP-005-2

3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Purchasing Selling Entities.

5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

   Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The ISN data recipient failed to sign the NERC Confidentiality Agreement for "Electric System Reliability Data".
R2	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.
R3	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Removed the Reliability Coordinator from the list of responsible functional entities Deleted R1 and R1.1 Modified M1 to omit the reference to the Reliability Coordinator Deleted VSLs for R1 and R1.1	Revised
2	March 23, 2011	Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)	

Attachment 1-TOP-005

Electric System Reliability Data

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

1. The following information shall be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

1.1.1 Status.

1.1.2 MW or ampere loadings.

1.1.3 MVA capability.

1.1.4 Transformer tap and phase angle settings.

1.1.5 Key voltages.

1.2. Generator data.

1.2.1 Status.

1.2.2 MW and MVAR capability.

1.2.3 MW and MVAR net output.

1.2.4 Status of automatic voltage control facilities.

1.3. Operating reserve.

1.3.1 MW reserve available within ten minutes.

1.4. Balancing Authority demand.

1.4.1 Instantaneous.

1.5. Interchange.

1.5.1 Instantaneous actual interchange with each Balancing Authority.

1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.

1.5.3 Interchange Schedules for the next 24 hours.

1.6. Area Control Error and frequency.

1.6.1 Instantaneous area control error.

1.6.2 Clock hour area control error.

1.6.3 System frequency at one or more locations in the Balancing Authority.

2. Other operating information updated as soon as available.

2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.

2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.

2.3. Forecast peak demand for current day and next day.

2.4. Forecast changes in equipment status.

2.5. New facilities in place.

2.6. New or degraded special protection systems.

2.7. Emergency operating procedures in effect.

2.8. Severe weather, fire, or earthquake.

2.9. Multi-site sabotage.

A. Introduction

1. **Title:** **Monitoring System Conditions**

2. **Number:** TOP-006-2

3. **Purpose:** To ensure critical reliability parameters are monitored in real-time.

4. **Applicability**

    4.1. Transmission Operators.

    4.2. Balancing Authorities.

    4.3. Generator Operators.

    4.4. Reliability Coordinators.

5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

    In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.

R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

C. Measures

M1. The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. (Requirement 1.2)

M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.

M4. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system's near-term load pattern. (Requirement 4)

M5. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)

M6. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift-operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measure 2.

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure 3, 5 and 6.

Each Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity failed to know the status of all generation and transmission resources available for use, even though said information was reported by the Generator Operator, Transmission Operator, or Balancing Authority.
R1.1	N/A	N/A	N/A	The Generator Operator failed to inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
R1.2	N/A	N/A	N/A	The responsible entity failed to inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
R2	N/A	The responsible entity monitors the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, but is not aware of the status of rotating and static reactive resources.	The responsible entity fails to monitor all of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of all rotating and static reactive resources.	The responsible entity fails to monitor any of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
R3	The responsible entity failed to provide any of the appropriate technical information concerning protective relays to their operating personnel.	N/A	N/A	The responsible entity failed to provide all of the appropriate technical information concerning protective relays to their operating personnel.

R#	Lower	Moderate	High	Severe
R4	N/A	N/A	The responsible entity has either weather forecasts or past load patterns, available to predict the system's near-term load pattern, but not both.	The responsible entity failed to have both weather forecasts and past load patterns, available to predict the system's near-term load pattern.
R5	N/A	N/A	The responsible entity used monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions, but does not have indication of the need for corrective action.	The responsible entity failed to use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions.
R6	N/A	N/A	N/A	The responsible entity failed to use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
R7	N/A	N/A	N/A	The responsible entity failed to monitor system frequency.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Modified R4 Modified M4 Modified Data Retention for M4 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	
2	March 23, 2011	Order issued by FERC approving TOP-006-2 (approval effective 5/23/11)	

A. Introduction

1. **Title:** Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations

2. **Number:** TOP-007-0

3. **Purpose:**

   This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.

R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.

R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.

R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

C. Measures

M1. Evidence that the Transmission Operator informed the Reliability Coordinator when an IROL or SOL was exceeded and the actions taken to return the system to within limits.

M2. Evidence that the Transmission Operator returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.

M3. Evidence that the Reliability Coordinator evaluated actions and provided direction required to return the system to within limits.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   The Reliability Coordinator shall report any IROL violation exceeding 30 minutes to the Regional Reliability Organization and NERC within 72 hours. Each Regional Reliability Organization shall report any such violations to NERC via the NERC compliance reporting process. The Reliability Coordinator shall report any SOL violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:

1.1.1. System instability.

1.1.2. Unacceptable system dynamic response or equipment tripping.

1.1.3. Voltage levels in violation of applicable emergency limits.

1.1.4. Loadings on transmission facilities in violation of applicable emergency limits.

1.1.5. Unacceptable loss of load based on regional and/or NERC criteria.

1.2. Compliance Monitoring Period and Reset Timeframe

The reset period is monthly.

1.3. Data Retention

The data retention period is three months.

2. Levels of Non-Compliance

2.1. The Transmission Operator did not inform the Reliability Coordinator of an IROL or an SOL that has become an IROL because of changed system conditions, and the actions they are taking to return the system to within limits, or

2.2. The Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the system to within the IROL within 30 minutes. (See Table 1-TOP-007-0 below.)

2.3. The limit violation was reported to the Reliability Coordinator, who did not provide appropriate direction to the Transmission Operator, resulting in an IROL violation in excess of 30 minutes duration.

Table 1-TOP-007-0 IROL and SOL Reporting Levels of Non-Compliance

Percentage by which IROL or SOL that has become an IROL is exceeded*	Limit exceeded for more than 30 minutes, up to 35 minutes.	Limit exceeded for more than 35 minutes, up to 40 minutes.	Limit exceeded for more than 40 minutes, up to 45 minutes.	Limit exceeded for more than 45 minutes.
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

*Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Response to Transmission Limit Violations**

2. **Number:** TOP-008-1

3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.

4. **Applicability**

    4.1. Transmission Operators.

5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.

R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

C. Measures

M1. The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)

M2. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1

M3. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)

M4. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents,

copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)

M5. The Transmission Operator that violates an SOL shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.

Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Transmission Operator

2.1. **Level 1:** Not applicable.

2.2. **Level 2:** Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.

2.3. **Level 3:** Not applicable.

2.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.

2.4.2 Did not disconnect an overloaded facility as specified in R3.

2.4.3 Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)

2.4.4 Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document

Project 2007-03 Real-time Operations

Mapping document showing the translation of TOP-001-1 — Reliability Responsibilities and Authorities; TOP-002-2a — Normal Operations Planning; TOP-003-1 — Planned Outage Coordination; TOP-004-2 — Transmission Operations; TOP-005-2 — Operational Reliability Information; TOP-006-2 – Monitoring System Conditions; TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations; TOP-008-1 - Response to Transmission Limit Violations; PRC-001-1 – System Protection Coordination; and PER-001-0 - Operating Personnel Responsibility and Authority.

Standard TOP-001-1 — Reliability Responsibilities and Authorities		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	Deleted	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions, as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the bulk power System have been more clearly laid out in revised standards. (See FERC Order 693a, Paragraph 112.) The requirement is also non-specific, ambiguous, and not performance-oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, which makes this requirement superfluous; and, thus, it can be deleted.

		FERC Order 693a, Paragraph 112: "In response to Avista, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of reliability standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize Reliability Coordinators to issue directives. Under the voluntary reliability scheme in place prior to Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a Reliability Coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies, including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	Proposed TOP-001-2, Requirement R11	Replaced by proposed TOP-001-2, R11: The undefined term 'operating emergencies' is no longer utilized, and the requirement has been made more stringent by not restricting Transmission Operator actions to that undefined condition. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant time frame. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued	Proposed IRO-001-3, Requirements R2, R3 & R4.	Replaced by: IRO-001-3, R2. Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent

by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.		identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-001-3, R3. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall comply with its Reliability Coordinator's direction per Requirement R2, unless the direction per Requirement R2 cannot be implemented or such actions would violate safety, equipment, regulatory or statutory requirements. IRO-001-3, R4. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform, as directed per Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	Proposed TOP-001-2, Requirements R1 & R2	Replaced by proposed: TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each reliability directive issued and identified as such by its Transmission Operator(s), unless such actions would violate safety, equipment, regulatory, or statutory requirements. TOP-001-2, R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified reliability directive issued by that Transmission Operator.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate	Proposed TOP-001-2, Requirement R3 Proposed TOP-001-2, Requirement R11.	Replaced by proposed: TOP-001-2, R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis.

the emergency.		TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant time frame.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	Proposed TOP-001-2, Requirement R4 for the Transmission Operator. Approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 for the Balancing Authority	Replaced by proposed TOP-001-2, R4. TOP-001-2, R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Generator Operator was deleted from this requirement since it can't be contacted directly by others and will only respond to such requests if they were in the form of a reliability directive from its Transmission Operator, which is covered in proposed TOP-001-2, Requirement R1. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 covers the Balancing Authority. So to eliminate a redundancy, the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission Operator, as stated in proposed TOP-001-2, Requirement R1. EOP-001-2b, R1. Balancing Authorities shall have

		operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: R7.1 - For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.2 - For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.3 - When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R5	R7: Replaced by proposed TOP-001-2, R5 for the Transmission Operator. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. R7 – The Generator Operator can't know if their actions will burden neighboring Systems, since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring Systems and is required to act on this information, as per proposed TOP-001-2, R5. R7.1 – Replaced by proposed TOP-001-2, R5 for both the Transmission Operator and the Generator Operator. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. R7.2 - Replaced by proposed TOP-001-2, R5 for the Transmission Operator. After-the-fact notifications have been replaced by the proposed TOP-003-2, R1 and approved IRO-010-1a, since those actions will now be seen through telemetry.

notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.		TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading Outages.
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance, it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	Approved EOP-002-3, Requirement R6. Approved VAR-001-1, Requirement R8. Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirements R1, R8, and R12. Approved IRO-009-1, Requirements R1 and R2. Approved EOP-003-1, Requirement R1.	Real Power Balance and Reactive Power Balance are not defined terms. First sentence – Real Power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance Real Power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – Reactive Power: Replaced by Approved VAR-001-1, Requirement R8 for the Transmission Operator, which covers Reactive Power requirements and the meaning of balancing Reactive Power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding Reactive Power per the NERC Functional Model V5 (see proposed TOP-001-2, Requirement R1) and, therefore, the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding

		Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, the Balancing Authority is not necessary. Replaced by approved VAR-001-1, Requirements R1, R8, and R12 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-1, Requirement R1 for the Transmission Operator and Balancing Authority. EOP-002-3, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. VAR-001-1 R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. VAR-001-1, R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, Load shedding – to maintain System and Interconnection voltages within established limits. VAR-001-1, R12. The Transmission Operator shall direct corrective action, including Load reduction necessary to prevent voltage collapse when reactive resources are insufficient. TOP-001-2, R1. Each Balancing Authority, Generator

		Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. IRO-009-1, R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more operating processes, procedures, or plans that identify actions it shall take, or actions it shall direct others to take (up to and including Load shedding) that can be implemented in time to prevent exceeding those IROLs. IRO-009-1, R2.For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more operating processes, procedures, or plans that identify actions it shall take, or actions it shall direct others to take (up to and including Load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load rather than risk an uncontrolled failure of components or Cascading Outages of the Interconnection.
Standard TOP-002-2a — Normal Operations Planning		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for	Approved BAL-001-0.1a. Approved BAL-002-1.	First sentence – Deleted for Balancing Authority, retained for Transmission Operator. The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and

reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	Approved EOP-002-2.1, Requirement R6. Proposed TOP-002-3, Requirements R1 through R3.	must take action, per approved EOP-002-2.1, Requirement R6 and, thus, the Balancing Authority part of this sentence can be deleted. Retained for Transmission Operator and moved to proposed TOP-002-3, Requirements R1 through R3. This is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator. Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities, as per their certification as NERC registered entities. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing Real Power demand and supply in Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of Load, and because Contingency Reserve activation does not typically apply to the loss of Load, the application of DCS is limited to the loss of supply, and does not apply to the loss of Load. EOP-002-2.1, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. TOP-002-3, R1: Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.

		TOP-002-3, R2: Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. TOP-002-3, R3: Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	Deleted	The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and, as such, this requirement is no longer needed and can be deleted. Functional Model V5: Transmission Operator: The entity responsible for the reliability of its "local" transmission System, and that operates or directs the operations of the transmission Facilities.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	Proposed TOP-003-2. Approved MOD-001-1a, Requirements R1 & R2. Approved MOD-030-2, Requirement R3.	For all but the Transmission Service Provider, moved to proposed TOP-003-2 requires the transfer of any and all required data, regardless of time frame involved. The Transmission Service Provider provisions are already covered in: • Approved MOD-001-1a, Requirement R1: Transmission Operators select transfer capability methodology from approved MOD-028, -029, or -030. • Approved MOD-030-2, Requirement R3: Transmission Operator gives transmission model updated at least once per day to Transmission Service Provider.

		• Approved MOD-001-1a, Requirement R2: Transmission Service Providers use the methodology designated in approved MOD-001-1a, Requirement R1 by the Transmission Operator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. MOD-001-1a, R1. Each Transmission Operator shall select one of the methodologies listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. MOD-030-2, R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [LA1]MOD-001-1a, R2. Each Transmission Service Provider shall calculate ATC or AFC values, as listed below, using[LA2] the methodology or methodologies selected by its Transmission Operator(s).
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator so that normal Interconnection operation will proceed in an orderly and consistent manner.	Proposed TOP-003-2, Requirement R5. Approved IRO-010-1a, Requirement R3.	Proposed TOP-003-2 requires the transfer of any and all required data between and amongst Balancing Authorities and Transmission Operators, regardless of the time frame involved. Data requirements for Reliability Coordinators are covered in approved IRO-010-1a, Requirement R3 making this requirement redundant for Reliability Coordinators, so the Reliability Coordinator has been removed here. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

		specifications for data. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	Approved BAL-001-0.1a. Proposed TOP-003-2, Requirement R4. Proposed TOP-002-3, Requirement R1.	The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built into the Functional Model. Therefore, the Transmission Operator should be developing the plan and passing it down to the Balancing Authority. The Balancing Authority provides any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R5. The part of the requirement dealing with the Transmission Operator has been moved to proposed TOP-002-3, Requirement R1. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing Real Power demand and supply in Real-time. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

		specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in System configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	Approved BAL-002-1, Requirements R2 – R4. Proposed TOP-003-2, Requirement R5. Proposed TOP-002-3, Requirement R1	The part of this requirement dealing with the Balancing Authority is replaced by approved BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R4. The part of the requirement dealing with the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. The n-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning. The SDT does not believe that there is a need for the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards.

		As stated in the NERC Functional Model V5: " the Balancing Authority's mission is to maintain the balance between Loads and resources in Real-time within its Balancing Authority Area by keeping its actual Interchange equal to its scheduled Interchange and meeting its frequency bias obligation." To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and approved BAL-002-1), Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any System condition. Balancing Authorities are not responsible for the operation of the transmission System. The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview and, as such, has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding Load, generation and Interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or Load shedding). If the Balancing Authorities' actions do not resolve the transmission issues, it is the Transmission Operators' or Reliability Coordinators' responsibility to direct alternative actions. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: BAL-002-1, R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. BAL-002-1, R4. Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator,

		Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. FAC-010-2.1, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-011-2, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-014-2, Purpose. To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing Real Power demand and supply in Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of Load and because Contingency

		Reserve activation does not typically apply to the loss of Load, the application of DCS is limited to the loss of supply and does not apply to the loss of Load.
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	Approved BAL-002-1, Requirement R2. Proposed TOP-002-3, Requirement R1.	The Balancing Authority is required to always plan to meet and recover from Contingency events, as stated in approved BAL-002-1, Requirement R2 and, therefore, this requirement is redundant and can be deleted, as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and are replaced by proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations, since any deliverability problems will appear as limit violations in the analysis. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirement R1. Proposed TOP-002-3, Requirement R1	The Balancing Authority must be told by the Transmission Operator to take actions regarding Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted, as all elements of the requirement are now covered in other standards. Voltage and Reactive Power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is replaced by proposed TOP-002-3, Requirement

		R1 since any deliverability problems will appear as limit violations in the analysis. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	Approved INT-003-2, Requirement R1.	Replaced by approved INT-003-2, R1. INT-003-2, R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Deleted for Balancing Authority. Proposed TOP-002-3, Requirements R1 & R2.	Balancing Authority - The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary, and, thus, this requirement should never have been applicable to the Balancing Authority. SOLs and IROLs are limits for which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations.

		As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between Loads and resources in Real-time within its Balancing Authority Area by keeping its actual Interchange equal to its scheduled Interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the bulk power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. Transmission Operator – replaced by proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs). TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. TOP-002-3, R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability in its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall	Approved FAC-011-2. Approved FAC-014-2.	First sentence – Replaced by FAC-011-2 and FAC-014-2 where SOLs are determined. FAC-011-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	Proposed TOP-002-3, Requirements R1 & R3.	FAC-014-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. Second sentence – Replaced by approved FAC-014-2, R2 & R5.1. FAC-014-2, R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2, R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. Third sentence – Replaced by proposed TOP-002-3. 'update… as necessary' is ambiguous and the SDT believes that proposed TOP-002-3 is a better solution. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-002-3, R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total	Approved MOD-028-1, Requirement R6.1. Approved MOD-029-1a, Requirement R3. Approved MOD-	Replaced by approved MOD-028-1, Requirement R6.1, MOD-029-1a, Requirement R3, and MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included.

Transfer Capability and Available Transfer Capability calculation processes.	30-2 Requirement R2.4.	MOD-028-1, R6.1,Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing Load within the source Balancing Authority area and decreasing generation and/or increasing Load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's System, or A SOL is reached on any other adjacent System in the Transmission model that is not on the study path and the distribution factor is 5% or greater. MOD-029-1a, R3, Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. MOD-030-2, R2.4, Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	Proposed MOD-25-2, Requirement R1 Proposed TOP-003-2, Requirement R5	Replaced by proposed MOD-025-2, R1. MOD-025-2, R1: Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the

		data is recorded to its Transmission Planner. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics; including but not limited to: 14.1 - Changes in real and reactive output capabilities. (Retired August 1, 2007) 14.2 - Changes in real output capabilities. (Effective August 1, 2007) 14.3 - Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: 16.1	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.

- Changes in transmission facility status. 16.2 - Changes in transmission facility rating		
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	Deleted	This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a System reliability issue. This is an administrative item, as seen in the measure, which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities, and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	Deleted	This is part of an entity's certification and is no longer required in standards. Furthermore, accuracy is a relative term that would be difficult to measure and assess compliance with. What is accurate? All calculated line flows are within 5% of actual flows? What if 14,999 lines out of 15,000 had calculated line flows within 5% and the 15,000th had a 6% error? Do we now call the model inaccurate and not rely on the results? How do you define actual flows when meters have accuracy errors, as well (i.e., no perfect meter exists)?
Standard TOP-003-1 — Planned Outage Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment

R1. Generator Operators and Transmission Operators shall provide planned outage information. 1.1 - Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. 1.2 - Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. 1.3 - Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	Proposed TOP-003-2, Requirements R1 & R2	Replaced by proposed TOP-003-2, Requirements R1 & R2. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring.
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R1 Proposed TOP-003-	Replaced by: proposed TOP-001-2, Requirement R5 which requires the Transmission Operator to coordinate actions while proposed TOP-003-2, Requirement R1 requires the Transmission Operator to identify the data it needs from the Balancing Authority to coordinate outages of voltage regulation equipment. Further, proposed TOP-003-2,

generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators, as required.	2, Requirement R5	Requirement R5 requires the Balancing Authority to provide the data to the Transmission Operator that the Transmission Operator identified it needs. TOP-001-2, R5: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations, known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-003-2, R1: Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R5: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	Proposed TOP-001-2, Requirement R6	Moved to proposed TOP-001-2, Requirement R6 TOP-001-2, R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC-registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	Proposed IRO-001-3, R2 Proposed IRO-005-4, R1	Moved to the proposed IRO-001-3, Requirements R3 and proposed IRO-005-4, Requirement R1 which gives the Reliability Coordinator the authority to resolve the conflict. IRO-001-3, R2: Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability

		Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-005-4, R1: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.
Standard TOP-004-2 — Transmission Operations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	Proposed TOP-001-2, Requirements R7and R9	Moved to proposed TOP-001-2, Requirements R7and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL)

		identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. These requirements are not limited by single or multiple Contingencies, but are based solely on identified IROLs (and selected SOLs), regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator. FAC-011-02 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. FAC-014-2, R6 requires the Planning Coordinator to identify the subset of multiple Contingencies from TPL-003 which result in stability limits and to provide this list to the Reliability Coordinators. FAC-011-2, R3.3 requires the Reliability Coordinator to include in their SOL methodology a process for determining which of the stability limits associated with multiple Contingencies are used to establish SOLs. FAC-014-2, R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. FAC-014-2, R1 requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area, while FAC-014-2, R2 also requires the TOP to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. FAC-011-2, R1, The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

		FAC-011-2, R3, The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.3. A process for determining which of the stability limits associated with the list of multiple Contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon, given the actual or expected System conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple Contingencies. FAC-014-2, R1, The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. FAC-014-2, R2, The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2 R6, The Planning Authority shall identify the subset of multiple Contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1. The Planning Authority shall provide this list of multiple Contingencies and the associated stability limits to the Reliability Coordinators that monitor the Facilities associated with these Contingencies and limits. R6.2. If the Planning Authority does not identify any stability-related multiple Contingencies, the

		Planning Authority shall so notify the Reliability Coordinator. TOP-001-2, R7: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	Proposed TOP-001-2, Requirements R7 and R9 Approved EOP-006-2	The SDT has determined a better way to handle such a situation is to treat it like an IROL or restoration scenario, and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is replaced by proposed TOP-001-2, Requirements R7 and R9 and the approved EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power System. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. EOP-006-2, Purpose: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
R5. Each Transmission Operator shall make every effort to remain connected to the	Deleted	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability

Interconnection. If the Transmission Operator determines that by remaining interconnected it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.		Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is a moot point under the Functional Model definitions and can be deleted.
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: 6.1 - Monitoring and controlling voltage levels and real and reactive power flows. 6.2 - Switching transmission elements. 6.3 - Planned outages of transmission elements. 6.4 - Responding to IROL and SOL violations.	Proposed TOP-001-2 Approved VAR-001-1, Requirement R1 Proposed TOP-001-2, Requirements R7 and R9 ProposedTOP-001-2, Requirement R5 Proposed TOP-001-2, Requirement R11	The first sentence has been superseded by the NERC Reliability Standards, taken as a whole. Examples of such would be the proposed TOP-001-2. The second sentence was replaced as follows: R6.1 is duplicative of approved VAR-001-1, Requirement R1 for Reactive. Real Power flows are covered in proposed TOP-001-2, Requirements R7 and R9. R6.2 is covered in proposed TOP-001-2, Requirement R5. R6.3 – moved to proposedTOP-001-2, Requirement R5. R6.4 – moved to proposed TOP-001-2, Requirement R11. TOP-001-2, Purpose: To prevent instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

		TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard TOP-005-2 — Operational Reliability Information		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area. 1.1 - Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any	Approved IRO-010-1a, Requirement R3	Moved to approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.

additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.		
R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Deleted	Confidentiality is not a reliability issue, but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.
R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R4. Each Purchasing-Selling Entity shall provide information, as requested by its Host Balancing Authorities and Transmission Operators, to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted	Deleted as redundant to NAESB standard –All operating data that a Purchasing Selling Entity has, that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-2 – Monitoring System Conditions		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. 1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. 1.2 - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	R1 & R1.1 are replaced by proposed TOP-003-2, Requirement R1. R1.2 – replaced by approved IRO-010-1a, Requirement R3. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3. Approved BAL-005-0.1b. Proposed TOP-001-2, Requirement R10. Approved IRO-008-1, Requirement R2.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-

		time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading outages. The act of monitoring is un-measureable. Entities will be in violation of other standards if they don't perform adequate monitoring. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs, and approved IRO-008-1, Requirement R2 for Real-time assessments every 30 minutes for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

		TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading outages.
R4. Each Transmission Operator and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading outages.
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to	Deleted	Deleted as this is covered in the certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs; approved IRO-008-1, Requirement R2

indicate, if appropriate, the need for corrective action.		for Real-time assessments every 30 minutes for Reliability Coordinators BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R7 for Transmission Operator avoiding IROLs. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, Requirement R2 for Transmission Operator avoiding underfrequency; approved EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. EOP-003-1, R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic Load shedding for underfrequency or undervoltage conditions. EOP-006-2, R8. The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization.
Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded, and the actions being taken to return the system to within limits.	Proposed TOP-001-2, Requirement R10	Moved to proposed TOP-001-2, Requirement R10. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.

R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	Proposed TOP-001-2, Requirement R11	Moved to proposed TOP-001-2, Requirement R11. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. A Transmission Operator shall take all appropriate actions, up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	Approved EOP-003-1, Requirements R1 and in proposed EOP-003-2, Requirement R1	Replaced by approved EOP-003-1, Requirements R1. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load rather than risk an uncontrolled failure of components or Cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	Approved IRO-008-1, Requirement R3	Replaced by approved IRO-008-1, Requirement R3. IRO-008-1, R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.
Standard TOP-008-1 - Response to Transmission Limit Violations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	Approved EOP-003-1, Requirements R1 and in proposed EOP-003-2, Requirement R1 Proposed TOP-001-2, Requirement R11	Replaced by approved EOP-003-1, Requirements R1 and proposed TOP-001-2, Requirement R11. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load, rather than risk an uncontrolled failure of components or Cascading Outages of the Interconnection. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement

		R8.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	Proposed TOP-001-2, Requirements R7 and R9 Approved IRO-009-1, Requirement R5	First sentence – Replaced by proposed TOP-001-2, Requirements R7 and R9. Second sentence – Replaced by approved IRO-009-1, Requirement R5 for the Reliability Coordinator who is now responsible for such matters. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. IRO-009-1, R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	Deleted	Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other reliability standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted	Proposed TOP-003-2, Requirement R1 Proposed TOP-002-3, Requirement R1	Data piece is replaced by proposed TOP-003-2, Requirement R1. Analysis tools are covered in the certification process for core capabilities and, therefore, are not needed

in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	Proposed TOP-001-2, Requirement R7 Proposed TOP-001-2, Requirement R11	here. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Replaced by proposed TOP-002-3, Requirement R1 for analysis. Replaced by proposed TOP-001-2, Requirement R7 for real-time analysis required for IROL mitigation. Proposed TOP-001-2, Requirement R11 covers mitigation of limit violations. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard PER-001-0 - Operating Personnel Responsibility and Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable	Deleted	In FERC Order 693a, Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of reliability standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and

operation of the Bulk Electric System.		Balancing Authorities and that makes this requirement superfluous and, thus, it can be deleted. FERC Order 693a, Paragraph 112: In response to Avista, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of reliability standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a Reliability Coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, these are vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
Standard PRC-001-1 – System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in New Standard or Comment**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others: R5.1. Each Generator Operator	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems. R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.		specifications for data.
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Mapping Document

Project 2007-03 Real-time Operations

Mapping document showing the translation of TOP-001-1 — Reliability Responsibilities and Authorities; TOP-002-2a — Normal Operations Planning; TOP-003-1 — Planned Outage Coordination; TOP-004-2 — Transmission Operations; TOP-005-2 — Operational Reliability Information; TOP-006-2 – Monitoring System Conditions; TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations; TOP-008-1 - Response to Transmission Limit Violations; PRC-001-1 – System Protection Coordination; and PER-001-0 - Operating Personnel Responsibility and Authority.

Standard TOP-001-1 — Reliability Responsibilities and Authorities		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	Deleted	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions, as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the bulk power ~~system~~System have been more clearly laid out in revised standards. (See FERC Order 693a, ~~paragraph~~ Paragraph 112.) The requirement is also non-specific, ambiguous, and not performance~~-~~oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power ~~system~~System is not adversely affected by the deletion of this requirement. In FERC Order 693a, ~~paragraph~~ Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities~~, –~~, which makes this requirement superfluous~~,~~; and, thus, it can be

		deleted. FERC Order 693a, ~~paragraph~~Paragraph 112: "In response to Avista, the Commission clarifies that a ~~reliability~~ Reliability ~~coordinator's~~ Coordinator's authority to issue directives arises out of the Commission's approval of ~~Reliability~~ reliability ~~Standards~~ standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize ~~reliability~~ Reliability ~~coordinators~~ Coordinators to issue directives. Under the voluntary reliability scheme in place prior to ~~section~~ Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a ~~reliability~~ Reliability ~~coordinator's~~ Coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies, including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	Proposed TOP-001-2, Requirement R11	Replaced by proposed TOP-001-2, R11: The undefined term 'operating emergencies' is no longer utilized, and the requirement has been made more stringent by not restricting Transmission Operator actions to that undefined condition. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant time frame. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator,	Proposed IRO-001-3, Requirements R2, R3 & R4.	Replaced by: IRO-001-3, R2. Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators,

and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.		Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-001-3, R3. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall comply with its Reliability Coordinator's direction per Requirement R2, unless the direction per Requirement R2 cannot be implemented or such actions would violate safety, equipment, regulatory or statutory requirements. IRO-001-3, R4. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall inform its Reliability Coordinator~~-~~ upon recognition of its inability to perform, as directed per Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	Proposed TOP-001-2, Requirements R1 & R2	Replaced by proposed: TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~Reliability~~ reliability ~~Directive~~ directive issued and identified as such by its Transmission Operator(s), unless such actions would violate safety, equipment, regulatory, or statutory requirements. TOP-001-2, R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified ~~Reliability~~ reliability ~~Directive~~ directive issued by that Transmission Operator.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or	Proposed TOP-001-2, Requirement R3 Proposed TOP-001-2, Requirement	Replaced by proposed: TOP-001-2, R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected

anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	R11.	by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant ~~timeframe~~time frame.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	Proposed TOP-001-2, Requirement R4 for the Transmission Operator. Approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 for the Balancing Authority	Replaced by proposed TOP-001-2, R4. TOP-001-2, R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Generator Operator was deleted from this requirement since it can't be contacted directly by others and will only respond to such requests if they were in the form of a ~~Reliability~~ reliability ~~Directive~~ directive from its Transmission Operator, which is covered in proposed TOP-001-2, Requirement R1. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 covers the Balancing Authority. ~~s~~So to eliminate a redundancy, the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission

		Operator, as stated in proposed TOP-001-2, Requirement R1. EOP-001-2b, R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: R7.1 - For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.2 - For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.3 - When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R5	R7: Replaced by proposed TOP-001-2, R5 for the Transmission Operator. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. R7 – The Generator Operator can't know if their actions will burden neighboring ~~system~~Systems, since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring ~~system~~Systems and is required to act on this information, as per proposed TOP-001-2, R5. R7.1 – Replaced by proposed TOP-001-2, R5 for both the Transmission Operator and the Generator Operator. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. R7.2 - Replaced by proposed TOP-001-2, R5 for the Transmission Operator.

damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.		After-~~-~~the-~~-~~fact notifications have been replaced by the proposed TOP-003-2, R1 and approved IRO-010-1a, since those actions will now be seen through telemetry. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and ~~cascading~~ Cascading ~~outages~~Outages.
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance, it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	Approved EOP-002-3, Requirement R6. Approved VAR-001-1, Requirement R8. Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirements R1, R8, and R12. Approved IRO-009-1, Requirements R1 and R2. Approved EOP-003-1, Requirement R1.	Real Power Balance and Reactive Power Balance are not defined terms. First sentence – ~~real power~~Real Power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance ~~real~~ Real ~~power~~ Power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – ~~reactive~~ Reactive ~~power~~Power: Replaced by Approved VAR-001-1, Requirement R8 for the Transmission Operator, which covers ~~reactive power~~Reactive Power requirements and the meaning of balancing ~~reactive power~~Reactive Power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding ~~reactive power~~Reactive Power per the NERC Functional Model V5 (see proposed TOP-001-2, Requirement R1) and, therefore, the Balancing

		Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding ~~reactive power~~Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, the Balancing Authority is not necessary. Replaced by approved VAR-001-1, Requirements R1, R8, and R12 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-1, Requirement R1 for the Transmission Operator and Balancing Authority. EOP-002-3, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. VAR-001-1 R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. VAR-001-1, R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, ~~load~~Load shedding – to maintain ~~system~~System and Interconnection voltages within established limits.

		VAR-001-1, R12. The Transmission Operator shall direct corrective action, including ~~load~~Load reduction ~~,~~ ~~necessary to~~necessary to prevent voltage collapse when reactive resources are insufficient. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. IRO-009-1, R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more ~~Operating~~ operating ~~Processes~~processes, ~~Procedures~~procedures, or ~~Plans~~ plans that identify actions it shall take, or actions it shall direct others to take (up to and including ~~load~~Load shedding) that can be implemented in time to prevent exceeding those IROLs. IRO-009-1, R2.For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more ~~Operating~~ operating ~~Processes~~processes, ~~Procedures~~procedures, or ~~Plans~~ plans that identify actions it shall take, or actions it shall direct others to take (up to and including ~~load~~Load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer ~~load~~Load rather than risk an uncontrolled failure of components or ~~cascading~~ Cascading ~~outages~~ Outages of the Interconnection.

Standard TOP-002-2a — Normal Operations Planning		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	Approved BAL-001-0.1a. Approved BAL-002-1. Approved EOP-002-2.1, Requirement R6. Proposed TOP-002-3, Requirements R1 through R3.	First sentence – Deleted for Balancing Authority, retained for Transmission Operator. The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and must take action, per approved EOP-002-2.1, Requirement R6 and, thus, the Balancing Authority part of this sentence can be deleted. Retained for Transmission Operator and moved to proposed TOP-002-3, Requirements R1 through R3. This is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator. Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities, as per their certification as NERC registered entities. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing ~~real power~~Real Power demand and supply in ~~real~~Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of ~~load~~Load, and because Contingency Reserve activation does not typically apply to the loss of ~~load~~Load, the application of DCS is limited to the loss of supply, and does not apply to the loss of ~~load~~Load. EOP-002-2.1, R6. If the Balancing Authority cannot comply with the Control Performance and

		Disturbance Control Standards, then it shall immediately implement remedies to do so. TOP-002-3, R1: Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. TOP-002-3, R2: Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. TOP-002-3, R3: Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	Deleted	The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and, as such, this requirement is no longer needed and can be deleted. Functional Model V5: Transmission Operator: The entity responsible for the reliability of its "local" transmission ~~system~~System, and that operates or directs the operations of the transmission ~~facilities~~Facilities.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-	Proposed TOP-003-2. Approved MOD-	For all but the Transmission Service Provider, moved to proposed TOP-003-2 requires the transfer of any and all required data, regardless of ~~timeframe~~time frame involved.

day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	001-1a, Requirements R1 & R2. Approved MOD-030-2, Requirement R3.	The Transmission Service Provider provisions are already covered in: • Approved MOD-001-1a, Requirement R1: Transmission Operators select transfer capability methodology from approved MOD-028, -029, or -030. • Approved MOD-030-2, Requirement R3: Transmission Operator gives transmission model updated at least once per day to Transmission Service Provider. • Approved MOD-001-1a, Requirement R2: Transmission Service Providers use the methodology designated in approved MOD-001-1a, Requirement R1 by the Transmission Operator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. MOD-001-1a, R1. Each Transmission Operator shall select one of the methodologies~~1~~ listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. MOD-030-2, R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [LA1]MOD-001-1a, R2. Each Transmission Service Provider shall calculate ATC or AFC values, as listed below, using[LA2] the methodology or methodologies selected by its Transmission Operator(s).
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-	Proposed TOP-003-2, Requirement R5. Approved IRO-010-	Proposed TOP-003-2 requires the transfer of any and all required data between and amongst Balancing Authorities and Transmission Operators, regardless of the ~~timeframe~~time frame involved.

day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator~~,~~ so that normal Interconnection operation will proceed in an orderly and consistent manner.	1a, Requirement R3.	Data requirements for Reliability Coordinators are covered in approved IRO-010-1a, Requirement R3 making this requirement redundant for Reliability Coordinators, so the Reliability Coordinator has been removed here. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	Approved BAL-001-0.1a. Proposed TOP-003-2, Requirement R4. Proposed TOP-002-3, Requirement R1.	The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in~~-~~to the Functional Model. Therefore, the Transmission Operator should be developing the plan and passing it down to the Balancing Authority. The Balancing Authority provides any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R5. The part of the requirement dealing with the Transmission Operator has been moved to proposed

		TOP-002-3, Requirement R1. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing ~~real power~~Real Power demand and supply in ~~real~~Real-time. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in System configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	Approved BAL-002-1, Requirements R2 – R4. Proposed TOP-003-2, Requirement R5. Proposed TOP-002-3, Requirement R1	The part of this requirement dealing with the Balancing Authority is replaced by approved ~~BAL-002-0 and proposed~~ BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R4.

		The part of the requirement dealing with the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. The n-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning. The SDT does not believe that there is a need for the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. As stated in the NERC Functional Model V5: " the Balancing Authority's mission is to maintain the balance between ~~load~~Loads and resources in ~~real time~~Real-time within its Balancing Authority Area by keeping its actual ~~interchange~~Interchange equal to its scheduled ~~interchange~~Interchange and meeting its frequency bias obligation." To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and ~~BAL-002-0 (and the proposed~~ approved BAL-002-1), Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any ~~system~~System condition. Balancing Authorities are not responsible for the operation of the transmission ~~system~~System. The Transmission Operator is responsible for the ~~real~~Real-time operating reliability of the transmission assets under its purview~~,~~ and, as such, has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding ~~load~~Load, generation and ~~interchange~~Interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or ~~load~~Load shedding). If the Balancing Authorities' actions do not resolve the transmission issues, it is the Transmission Operators' or Reliability Coordinators' responsibility to direct alternative actions.

		BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: BAL-002-1, R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. BAL-002-1, R4. Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. FAC-010-2.1, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-011-2, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-014-2, Purpose. To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are

		determined based on an established methodology or methodologies. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing ~~real power~~Real Power demand and supply in ~~real~~Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of ~~load~~Load and because Contingency Reserve activation does not typically apply to the loss of ~~load~~Load, the application of DCS is limited to the loss of supply and does not apply to the loss of ~~load~~Load.
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	Approved BAL-002-1, Requirement R2. Proposed TOP-002-3, Requirement R1.	The Balancing Authority is required to always plan to meet and recover from Contingency events, as stated in approved BAL-002-1, Requirement R2 and, therefore, this requirement is redundant and can be deleted, as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and are replaced by proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations, since any deliverability problems will appear as limit violations in the analysis. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next

		day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirement R1. Proposed TOP-002-3, Requirement R1	The Balancing Authority must be told by the Transmission Operator to take actions regarding ~~reactive power~~Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted, as all elements of the requirement are now covered in other standards. Voltage and ~~reactive power~~Reactive Power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is replaced by proposed TOP-002-3, Requirement R1 since any deliverability problems will appear as limit violations in the analysis. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during

		anticipated normal and Contingency event conditions.
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	Approved INT-003-2, Requirement R1.	Replaced by approved INT-003-2, R1. INT-003-2, R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Deleted for Balancing Authority. Proposed TOP-002-3, Requirements R1 & R2.	Balancing Authority - The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary, and, thus, this requirement should never have been applicable to the Balancing Authority. SOLs and IROLs are limits for which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between ~~load~~Loads and resources in ~~real time~~Real-time within its Balancing Authority Area by keeping its actual ~~interchange~~Interchange equal to its scheduled ~~interchange~~Interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the bulk power ~~system~~System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. Transmission Operator – replaced by proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs). TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during

		anticipated normal and Contingency event conditions. TOP-002-3, R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability in its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	Approved FAC-011-2. Approved FAC-014-2. Proposed TOP-002-3, Requirements R1 & R3.	First sentence – Replaced by FAC-011-2 and FAC-014-2 where SOLs are determined. FAC-011-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-014-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. Second sentence – Replaced by approved FAC-014-2, R2 & R5.1. FAC-014-2, R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2, R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. Third sentence – Replaced by proposed TOP-002-3.

		'update… as necessary' is ambiguous and the SDT believes that proposed TOP-002-3 is a better solution. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-002-3, R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Approved MOD-028-1, Requirement R6.1. Approved MOD-029-1a, Requirement R3. Approved MOD-30-2 Requirement R2.4.	Replaced by approved MOD-028-1, Requirement R6.1, MOD-029-1a, Requirement R3, and MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. MOD-028-1, R6.1,Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing ~~load~~Load within the source Balancing Authority area and decreasing generation and/or increasing ~~load~~Load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's ~~system~~System, or A SOL is reached on any other adjacent ~~system~~System in the Transmission model that is not on the study path and the distribution factor is 5% or greater. MOD-029-1a, R3, Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. MOD-030-2, R2.4, Establish the TFC of each of the defined Flowgates as equal to:

		For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	Proposed MOD-25-2, Requirement R1 Proposed TOP-003-2, Requirement R5	Replaced by proposed MOD-025-2, R1. MOD-025-2, R1: Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the data is recorded to its Transmission Planner. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, ~~Interchange~~Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics; including but not limited to: 14.1 - Changes in real and reactive output capabilities. (Retired August 1, 2007) 14.2 - Changes in real output capabilities. (Effective August 1, 2007) 14.3 - Automatic Voltage Regulator status and mode setting. (Retired August 1,	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

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R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: 16.1 - Changes in transmission facility status. 16.2 - Changes in transmission facility rating	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	Deleted	This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a ~~system~~System reliability issue. This is an administrative item, as seen in the measure, which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators

		as part of their normal responsibilities, and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	Deleted	This is part of an entity's certification and is no longer required in standards. Furthermore, accuracy is a relative term that would be difficult to measure and assess compliance with. What is accurate? All calculated line flows are within 5% of actual flows? What if 14,999 lines out of 15,000 had calculated line flows within 5% and the 15,000th had a 6% error? Do we now call the model inaccurate and not rely on the results? How do you ~~even~~ define actual flows when meters have accuracy errors, as well (i.e., no perfect meter exists)?
Standard TOP-003-1 — Planned Outage Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Generator Operators and Transmission Operators shall provide planned outage information. 1.1 - Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. 1.2 - Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50	Proposed TOP-003-2, Requirements R1 & R2	Replaced by proposed TOP-003-2, Requirements R1 & R2. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring.

MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. 1.3 - Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.		
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators, as required.	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R1 Proposed TOP-003-2, Requirement R5	Replaced by: proposed TOP-001-2, Requirement R5 which requires the Transmission Operator to coordinate actions while proposed TOP-003-2, Requirement R1 requires the Transmission Operator to identify the data it needs from the Balancing Authority to coordinate outages of voltage regulation equipment. Further, proposed TOP-003-2, Requirement R5 requires the Balancing Authority to provide the data to the Transmission Operator that the Transmission Operator identified it needs. TOP-001-2, R5: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations, known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-003-2, R1: Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R5: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data

		specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	Proposed TOP-001-2, Requirement R6	Moved to proposed TOP-001-2, Requirement R6 TOP-001-2, R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC--registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	Proposed IRO-001-3, R2 Proposed IRO-005-4, R1	Moved to the proposed IRO-001-3, Requirements R3 and proposed IRO-005-4, Requirement R1 which gives the Reliability Coordinator the authority to resolve the conflict. IRO-001-3, R2: Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-005-4, R1: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.
Standard TOP-004-2 — Transmission Operations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. TOP-001-2, R7. Each Transmission Operator shall not

System Operating Limits (SOLs).		operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	Proposed TOP-001-2, Requirements R7and R9	Moved to proposed TOP-001-2, Requirements R7and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. These requirements are not limited by single or multiple Contingencies, but are based solely on identified IROLs (and selected SOLs), regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator. FAC-011-02 and FAC-014-2 work collectively to establish how multiple ~~contingencies~~ Contingencies are considered in IROLs and SOLs. FAC-014-2, R6 requires the Planning Coordinator to identify the subset of multiple ~~contingencies~~ Contingencies from TPL-003 which result in stability limits and to provide this list to the Reliability Coordinators. FAC-011-2, R3.3 requires the Reliability Coordinator to include in their SOL methodology a process for determining which of the stability limits associated with multiple ~~contingencies~~ Contingencies are used to

		establish SOLs. FAC-014-2, R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. FAC-014-2, R1 requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area, while FAC-014-2, R2 also requires the TOP to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. FAC-011-2, R1, The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs. FAC-011-2, R3, The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.3. A process for determining which of the stability limits associated with the list of multiple ~~contingencies~~ Contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon, given the actual or expected ~~system~~System conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple ~~contingencies~~Contingencies. FAC-014-2, R1, The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

		FAC-014-2, R2, The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2 R6, The Planning Authority shall identify the subset of multiple ~~contingencies~~ Contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1. The Planning Authority shall provide this list of multiple ~~contingencies~~ Contingencies and the associated stability limits to the Reliability Coordinators that monitor the ~~facilities~~Facilities associated with these ~~contingencies~~ Contingencies and limits. R6.2. If the Planning Authority does not identify any stability-related multiple ~~contingencies~~Contingencies, the Planning Authority shall so notify the Reliability Coordinator. TOP-001-2, R7: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be	Proposed TOP-001-2, Requirements R7 and R9 Approved EOP-	The SDT has determined a better way to handle such a situation is to treat it like an IROL or restoration scenario, and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is replaced by proposed TOP-001-2,

considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	006-2	Requirements R7 and R9 and the approved EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power ~~system~~System. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. EOP-006-2, Purpose: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected~~,~~ it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	Deleted	Normally, ~~T~~the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is a moot point under the Functional Model definitions and can be deleted.
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that	Proposed TOP-001-2 Approved VAR-001-1, Requirement R1 Proposed TOP-001-2, Requirements R7 and R9	The first sentence has been superseded by the NERC Reliability Standards, taken as a whole. Examples of such would be the proposed TOP-001-2. The second sentence was replaced as follows: R6.1 is duplicative of approved VAR-001-1, Requirement R1 for ~~reactive~~Reactive. ~~Real power~~Real Power flows are covered in proposed TOP-001-2, Requirements R7 and R9.

impact inter- and intra-Regional reliability, including: 6.1 - Monitoring and controlling voltage levels and real and reactive power flows. 6.2 - Switching transmission elements. 6.3 - Planned outages of transmission elements. 6.4 - Responding to IROL and SOL violations.	ProposedTOP-001-2, Requirement R5 Proposed TOP-001-2, Requirement R11	R6.2 is covered in proposed TOP-001-2, Requirement R5. R6.3 – moved to proposedTOP-001-2, Requirement R5. R6.4 – moved to proposed TOP-001-2, Requirement R11. TOP-001-2, Purpose: To prevent instability, uncontrolled separation, or ~~cascading outages~~Cascading Outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

		TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard TOP-005-2 — Operational Reliability Information		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area. 1.1 - Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.	Approved IRO-010-1a, Requirement R3	Moved to approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Deleted	Confidentiality is not a reliability issue, but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.
R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.		specifications for data.
R4. Each Purchasing-Selling Entity shall provide information, as requested by its Host Balancing Authorities and Transmission Operators, to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted	Deleted as redundant to NAESB standard –All operating data that a Purchasing Selling Entity has, that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.
Standard TOP-006-2 – Monitoring System Conditions		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. 1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. 1.2 - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	R1 & R1.1 are replaced by proposed TOP-003-2, Requirement R1. R1.2 – replaced by approved IRO-010-1a, Requirement R3. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator,

Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.		Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3. Approved BAL-005-0.1b. Proposed TOP-001-2, Requirement R10. Approved IRO-008-1, Requirement R2.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and ~~cascading~~ Cascading outages. The act of monitoring is un-measureable. Entities will be in violation of other standards if they don't perform adequate monitoring. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs, and approved IRO-008-1, Requirement R2 for Real-time assessments every 30 minutes for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that

		all ~~facilities~~Facilities and ~~load~~Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the ~~system~~System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and ~~c~~Cascading outages.
R4. Each Transmission Operator~~,~~ and Balancing Authority shall have information, including weather forecasts and past load	Proposed TOP-003-2, Requirements R1 & R2	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority.

patterns, available to predict the system's near-term load pattern.	Approved IRO-010-1a, Requirement R3.	Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and ~~cascading~~ Cascading outages.
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	Deleted	Deleted as this is covered in the certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs; approved IRO-008-1, Requirement R2 for ~~real~~Real-time assessments every 30 minutes for Reliability Coordinators BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all ~~facilities~~Facilities and ~~load~~Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the ~~system~~System to within limits when an

		IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R7 for Transmission Operator avoiding IROLs. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all ~~facilities~~Facilities and ~~load~~Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, Requirement R2 for Transmission Operator avoiding underfrequency; approved EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the

		Regulating Reserve. The standard also ensures that all ~~facilities~~Facilities and ~~load~~Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. EOP-003-1, R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic ~~load~~Load shedding for underfrequency or undervoltage conditions. EOP-006-2, R8. The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization.
Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded, and the actions being taken to return the system to within limits.	Proposed TOP-001-2, Requirement R10	Moved to proposed TOP-001-2, Requirement R10. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the ~~system~~System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	Proposed TOP-001-2, Requirement R11	Moved to proposed TOP-001-2, Requirement R11. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. A Transmission Operator shall take all appropriate actions, up to and including shedding firm load,	Approved EOP-003-1, Requirements R1	Replaced by approved EOP-003-1, Requirements R1. EOP-003-1, R1. After taking all other remedial steps, a

or directing the shedding of firm load, in order to comply with Requirement R2.	and in proposed EOP-003-2, Requirement R1	Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer ~~load~~Load rather than risk an uncontrolled failure of components or ~~cascading~~ Cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	Approved IRO-008-1, Requirement R3	Replaced by approved IRO-008-1, Requirement R3. IRO-008-1, R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.

Standard TOP-008-1 - Response to Transmission Limit Violations

Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	Approved EOP-003-1, Requirements R1 and in proposed EOP-003-2, Requirement R1 Proposed TOP-001-2, Requirement R11	Replaced by approved EOP-003-1, Requirements R1 and proposed TOP-001-2, Requirement R11. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer ~~load~~Load, rather than risk an uncontrolled failure of components or ~~cascading outages~~Cascading Outages of the Interconnection. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the	Proposed TOP-001-2, Requirements R7 and R9 Approved IRO-009-1, Requirement R5	First sentence – Replaced by proposed TOP-001-2, Requirements R7 and R9. Second sentence – Replaced by approved IRO-009-1, Requirement R5 for the Reliability Coordinator who is now responsible for such matters. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection

Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.		Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. IRO-009-1, R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	Deleted	Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other ~~Reliability~~ reliability ~~Standards~~ standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	Proposed TOP-003-2, Requirement R1 Proposed TOP-002-3, Requirement R1 Proposed TOP-001-2, Requirement R7 Proposed TOP-001-2, Requirement R11	Data piece is replaced by proposed TOP-003-2, Requirement R1. Analysis tools are covered in the certification process for core capabilities and, therefore, are not needed here. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Replaced by proposed TOP-002-3, Requirement R1 for analysis. Replaced by proposed TOP-001-2, Requirement R7 for real-time analysis required for IROL mitigation.

		Proposed TOP-001-2, Requirement R11 covers mitigation of limit violations. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard PER-001-0 - Operating Personnel Responsibility and Authority		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.	Deleted	In FERC Order 693a, ~~paragraph~~Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of ~~Reliability~~ reliability ~~Standards~~ standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and, thus, it can be deleted. FERC Order 693a, ~~paragraph~~Paragraph 112: In response to Avista, the Commission clarifies that a ~~reliability~~ Reliability ~~coordinator's~~ Coordinator's authority to issue directives arises out of the Commission's approval of ~~Reliability~~ reliability ~~Standards~~ standards that mandate compliance with

		such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to ~~section~~ Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a ~~reliability~~ Reliability ~~coordinator's~~ Coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, ~~we view~~ these are~~as~~ vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
Standard PRC-001-1 – System Protection Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others: R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.		
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

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Standards Announcement

Project 2007-03 Real-Time Transmission Operations

Three Successive Ballots and Two Non-binding Polls Windows Now Open Through 8 p.m. Eastern on Friday, April 20, 2012

Now Available

Three successive ballots of the following standards and two non-binding polls of the associated VRFs and VSLs, are **open through 8 p.m. Eastern on Friday, April 20, 2012:**

- TOP-001-2 Transmission Operations (significant changes made to last posted version)
- TOP-002-3 Operations Planning (no significant changes made to last posted version)
- TOP-003-2 Operational Reliability Data (significant changes made to last posted version)

Clean and redline versions of these standards and the associated implementation plan and VRFs and VSLs, are posted on the project webpage. The implementation plan addresses all three proposed TOP standards and associated retirements and is not easily associated with a single proposed TOP standard. Since the most significant modifications to the implementation plan are associated with TOP-003-2, the comment form and ballot for TOP-003-2 will include the implementation plan.

The SDT is recommending that three requirements in PRC-001-1 be retired because those requirements deal with data requirements covered in the proposed TOP-003-2. The mapping document for the project shows each of the requirements in the approved standard(s) and the disposition of the requirement in the new standards. Clean and redline versions of PRC-001-2, showing the retired requirements, have been posted on the project page. The ballot of the conforming changes to PRC-001 is associated with the approval of TOP-003-2 and the implementation plan for this project.

Note that TOP-001-2, TOP-002-3, and TOP-003-2 reflect the merging of the following standards into a single standard, making it impractical to post a “redline” of the three proposed standards that shows the changes to the last balloted versions of these standards. The last approved versions of the standards listed below, as well as a redline showing the proposed modifications to PRC-001-1, have been posted on the project’s webpage for easy reference.

- PER-001-0.1 Operating Personnel Responsibility and Authority
- PRC-001-2 System Protection Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning

- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting SOL and IROL Violations
- TOP-008-1 Response to Transmission Limit Violations

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their votes for the standards and opinions for the non-binding polls by clicking here.

Please note that comments submitted during the formal comment period, the ballots and the non-binding polls use the same electronic form. Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. Companies or entities with representatives in multiple segments of the ballot pool may submit a single set of comments by identifying themselves as a "group" on the comment form. Likewise, it is **preferable** for a group of separate entities that develop comments jointly to submit the comments as a "group." **The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form, and that companies in multiple segments as well as individual entities that develop joint comments with other entities submit their comments as a "group," with the list of group members and their associated Industry Segments.**

Next Steps

The drafting team will consider all comments submitted during this formal comment and ballot period to determine whether to make additional revisions to the standards.

Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2007-03 Real-Time Transmission Operations
Formal Comment Period Open: March 22, 2012 – April 20, 2012
Ballot Windows Open – Three Successive Ballots, and Two Non-binding Polls: April 11–20, 2012

Now Available

The Real-time Operations Standards Drafting Team has made revisions to three standards and the associated VRFs, VSLs, and implementation plan in response to stakeholder comments from the last posting and quality review of each standard:

- TOP-001-2 Transmission Operations (significant changes made to last posted version
- TOP-002-3 Operations Planning (no significant changes made to last posted version)
- TOP-003-2 Operational Reliability Data (significant changes made to last posted version)

The drafting team did make significant changes to all three standards following the comment and ballot period that ended on January 12, 2012 and the team has posted the revised standards and implementation plan for a successive comment/ballot period.

The implementation plan addresses all three proposed TOP standards and associated retirements and is not easily associated with a single proposed TOP standard. Since the most significant modifications to the implementation plan are associated with TOP-003-2, the comment form and ballot for TOP-003-2 will include the implementation plan.

Clean and redline versions of TOP-001-2, TOP-002-3, and TOP-003-2, the associated implementation plan, and the VRFs and VSLs are posted for a formal 30-day comment period through 8 p.m. Eastern on Friday, April 20, 2012. Successive ballots of the three standards, and non-binding polls of the VRFs and VSLs associated with TOP-001-2 and TOP-003-2, will begin on Wednesday, April 11 and end on Friday, April 20, 2012. (There were no changes to the Requirements or associated VRFs and VSLs for TOP-002-3 thus there is no need to conduct another non-binding poll of these VRFs and VSLs.)

Note: The SDT is recommending that three requirements in PRC-001-1 be retired because those requirements deal with data requirements covered in the proposed TOP-003-2. The mapping document for the project shows each of the requirements in the approved standard(s) and the disposition of the requirement in the new standards. Clean and redline versions of PRC-001-2, showing the retired requirements, have been posted on the project page. The ballot of the conforming changes to PRC-001 is associated with the approval of TOP-003-2 and the implementation plan for this project.

Note that TOP-001-2, TOP-002-3, and TOP-003-2 reflect the merging of the following standards into a single standard, making it impractical to post a "redline" of the three proposed standards that shows the changes to the last balloted versions of these standards. The last approved versions of the standards listed below, as well as a redline showing the proposed modifications to PRC-001-1 have been posted on the project's web page for easy reference.

- PER-001-0 Operating Personnel Responsibility and Authority
- PRC-001-1 System Protection Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting SOL and IROL Violations
- TOP-008-1 Response to Transmission Limit Violations

Instructions for Submitting Comments

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted during the formal comment period, the ballot and the non-binding polls use the same electronic form. Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. Companies or entities with representatives in multiple segments of the ballot pool may submit a single set of comments by identifying themselves as a "group" on the comment form. Likewise, it is **preferable** for a group of separate entities that develop comments jointly to submit the comments as a "group." **The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form, and that companies in multiple segments as well as individual entities that develop joint comments with other entities submit their comments as a "group," with the list of group members and their associated Industry Segments.**

Next Steps

Three individual successive ballots (one for each standard) and two non-binding polls will be conducted beginning on Wednesday, April 11, 2012 and ending at 8 p.m. ET on Friday, April 20, 2012.

The standards are being balloted individually to provide stakeholders an opportunity to cast separate ballots for each standard. The individual ballots will provide the drafting team better feedback on which standards require additional development to achieve stakeholder consensus. Stakeholders are encouraged to consider each standard on its own merits and cast individual ballots, rather than casting the same ballot for both standards, in order to assist the drafting team with evaluating which standards require additional development to achieve consensus.

Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

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Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
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Standards Announcement

Project 2007-03 Real-Time Transmission Operations
Formal Comment Period Open: March 22, 2012 – April 20, 2012
Ballot Windows Open – Three Successive Ballots, and Two Non-binding Polls: April 11–20, 2012

Now Available

The Real-time Operations Standards Drafting Team has made revisions to three standards and the associated VRFs, VSLs, and implementation plan in response to stakeholder comments from the last posting and quality review of each standard:

- TOP-001-2 Transmission Operations (significant changes made to last posted version
- TOP-002-3 Operations Planning (no significant changes made to last posted version)
- TOP-003-2 Operational Reliability Data (significant changes made to last posted version)

The drafting team did make significant changes to all three standards following the comment and ballot period that ended on January 12, 2012 and the team has posted the revised standards and implementation plan for a successive comment/ballot period.

The implementation plan addresses all three proposed TOP standards and associated retirements and is not easily associated with a single proposed TOP standard. Since the most significant modifications to the implementation plan are associated with TOP-003-2, the comment form and ballot for TOP-003-2 will include the implementation plan.

Clean and redline versions of TOP-001-2, TOP-002-3, and TOP-003-2, the associated implementation plan, and the VRFs and VSLs are posted for a formal 30-day comment period through 8 p.m. Eastern on Friday, April 20, 2012. Successive ballots of the three standards, and non-binding polls of the VRFs and VSLs associated with TOP-001-2 and TOP-003-2, will begin on Wednesday, April 11 and end on Friday, April 20, 2012. (There were no changes to the Requirements or associated VRFs and VSLs for TOP-002-3 thus there is no need to conduct another non-binding poll of these VRFs and VSLs.)

Note: The SDT is recommending that three requirements in PRC-001-1 be retired because those requirements deal with data requirements covered in the proposed TOP-003-2. The mapping document for the project shows each of the requirements in the approved standard(s) and the disposition of the requirement in the new standards. Clean and redline versions of PRC-001-2, showing the retired requirements, have been posted on the project page. The ballot of the conforming changes to PRC-001 is associated with the approval of TOP-003-2 and the implementation plan for this project.

Note that TOP-001-2, TOP-002-3, and TOP-003-2 reflect the merging of the following standards into a single standard, making it impractical to post a "redline" of the three proposed standards that shows the changes to the last balloted versions of these standards. The last approved versions of the standards listed below, as well as a redline showing the proposed modifications to PRC-001-1 have been posted on the project's web page for easy reference.

- PER-001-0 Operating Personnel Responsibility and Authority
- PRC-001-1 System Protection Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination
- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting SOL and IROL Violations
- TOP-008-1 Response to Transmission Limit Violations

Instructions for Submitting Comments

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please note that comments submitted during the formal comment period, the ballot and the non-binding polls use the same electronic form. Therefore, it is NOT necessary for ballot pool members to submit more than one set of comments. Companies or entities with representatives in multiple segments of the ballot pool may submit a single set of comments by identifying themselves as a "group" on the comment form. Likewise, it is **preferable** for a group of separate entities that develop comments jointly to submit the comments as a "group." **The drafting team requests that all stakeholders (ballot pool members as well as other stakeholders) submit all comments through the electronic comment form, and that companies in multiple segments as well as individual entities that develop joint comments with other entities submit their comments as a "group," with the list of group members and their associated Industry Segments.**

Next Steps

Three individual successive ballots (one for each standard) and two non-binding polls will be conducted beginning on Wednesday, April 11, 2012 and ending at 8 p.m. ET on Friday, April 20, 2012.

The standards are being balloted individually to provide stakeholders an opportunity to cast separate ballots for each standard. The individual ballots will provide the drafting team better feedback on which standards require additional development to achieve stakeholder consensus. Stakeholders are encouraged to consider each standard on its own merits and cast individual ballots, rather than casting the same ballot for both standards, in order to assist the drafting team with evaluating which standards require additional development to achieve consensus.

Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

Standards Development Process

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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2007-03 – Real-time Operations

Successive Ballot and Non-binding Poll Results

Now Available

Successive ballots of three Real-time Operations standards concluded Friday, April 20 and non-binding polls of the associated VRFs and VSLs concluded Monday, April 23, 2012:

- TOP-001-2 Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Voting statistics for each ballot are listed below, and the Ballots Results page provides a link to the detailed results.

Standard	Quorum	Non-binding Poll Results
TOP-001-2 Transmission Operations	Quorum: 78.28% Approval: 75.65%	Quorum: 77.21% Supportive Opinions: 69.84%
TOP-002-3 Operations Planning	Quorum: 78.02% Approval: 87.22%	
TOP-003-2 Operational Reliability	Quorum: 78.28% Approval: 80.11%	Quorum: 77.48% Supportive Opinions: 67.64%

Next Steps

The drafting team will consider all comments submitted, and based on the comments will determine whether to make additional changes. If the drafting team determines that no substantive changes are required to address the comments, a recirculation ballot will be conducted. If the drafting team decides to make substantive revisions, the drafting team will submit the revised standard and consideration of comments received for a quality review prior to posting for a parallel formal 30-day comment period and successive ballot.

Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

Additional information is available on the project page.

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Update

Ballot Results	
Ballot Name:	Project 2007-03 SB TOP-001-2
Ballot Period:	4/11/2012 - 4/20/2012
Ballot Type:	Initial
Total # Votes:	292
Total Ballot Pool:	373
Quorum:	**78.28 % The Quorum has been reached**
Weighted Segment Vote:	75.44 %
Ballot Results:	**The drafting team is considering comments.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	53	0.757	17	0.243	5	28
2 - Segment 2.	11	0.9	8	0.8	1	0.1	0	2
3 - Segment 3.	82	1	49	0.766	15	0.234	3	15
4 - Segment 4.	27	1	16	0.762	5	0.238	1	5
5 - Segment 5.	82	1	44	0.759	14	0.241	8	16
6 - Segment 6.	47	1	26	0.788	7	0.212	3	11
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.4	2	0.2	2	0.2	0	4
9 - Segment 9.	4	0.3	1	0.1	2	0.2	1	0
10 - Segment 10.	9	0.6	5	0.5	1	0.1	3	0
Totals	**373**	**7.2**	**204**	**5.432**	**64**	**1.768**	**24**	**81**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt		
1	Muscatine Power & Water	Tim Reed		
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F Afranji	Affirmative	

1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Negative	View
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	View
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon		
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Affirmative	View
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	View
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	View
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Negative	View
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	View
3	Seattle City Light	Dana Wheelock	Affirmative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	View

4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Negative	
5	AES Corporation	Leo Bernier	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	View
5	Consumers Energy	James B Lewis	Negative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	View
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	
6	AEP Marketing	Edward P. Cox		
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Affirmative	

6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Merle Ashton		
8		Edward C Stein		
8	INTELLIBIND	Kevin Conway	Negative	View
8	JDRJC Associates	Jim Cyrulewski		
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	View
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Negative	View
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Abstain	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2007-03 Successive Ballot TOP-002-3
Ballot Period:	4/11/2012 - 4/20/2012
Ballot Type:	Initial
Total # Votes:	291
Total Ballot Pool:	373
Quorum:	**78.02 % The Quorum has been reached**
Weighted Segment Vote:	87.22 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	59	0.843	11	0.157	5	28
2 - Segment 2.	11	0.9	9	0.9	0	0	0	2
3 - Segment 3.	82	1	54	0.885	7	0.115	6	15
4 - Segment 4.	27	1	16	0.8	4	0.2	2	5
5 - Segment 5.	82	1	45	0.804	11	0.196	9	17
6 - Segment 6.	47	1	28	0.848	5	0.152	3	11
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.3	2	0.2	1	0.1	1	4
9 - Segment 9.	4	0.3	3	0.3	0	0	1	0
10 - Segment 10.	9	0.7	7	0.7	0	0	2	0
Totals	**373**	**7.2**	**223**	**6.28**	**39**	**0.92**	**29**	**82**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt		
1	Muscatine Power & Water	Tim Reed		
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F Afranji	Affirmative	

1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	View
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	View
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon		
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Affirmative	View
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	View
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	

4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Abstain	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	View
5	Consumers Energy	James B Lewis	Negative	
5	Cowlitz County PUD	Bob Essex	Abstain	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Affirmative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	View
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
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6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Affirmative	

6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
8		James A Maenner		
8		Merle Ashton		
8	INTELLIBIND	Kevin Conway	Negative	View
8	JDRJC Associates	Jim Cyrulewski		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

Ballot Results	
Ballot Name:	Project 2007-03 SB TOP-003-2
Ballot Period:	4/11/2012 - 4/20/2012
Ballot Type:	Initial
Total # Votes:	292
Total Ballot Pool:	373
Quorum:	**78.28 % The Quorum has been reached**
Weighted Segment Vote:	80.11 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	56	0.8	14	0.2	5	28
2 - Segment 2.	11	0.9	9	0.9	0	0	0	2
3 - Segment 3.	82	1	54	0.857	9	0.143	4	15
4 - Segment 4.	27	1	15	0.682	7	0.318	0	5
5 - Segment 5.	82	1	43	0.741	15	0.259	8	16
6 - Segment 6.	47	1	26	0.788	7	0.212	3	11
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.3	2	0.2	1	0.1	1	4
9 - Segment 9.	4	0.3	3	0.3	0	0	1	0
10 - Segment 10.	9	0.7	5	0.5	2	0.2	2	0
Totals	**373**	**7.2**	**213**	**5.768**	**55**	**1.432**	**24**	**81**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	East Kentucky Power Coop.	George S. Carruba	Negative	View
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Richard Burt		
1	Muscatine Power & Water	Tim Reed		
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F Afranji	Affirmative	

1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Rich Salgo	Negative	
1	South Texas Electric Cooperative	Richard McLeon		
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Affirmative	View
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Negative	View
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Affirmative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	View

4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	View
5	Consumers Energy	James B Lewis	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	View

5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Affirmative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Negative	View
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	View
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer		
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6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
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8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
8		Merle Ashton		
8		James A Maenner		
8	INTELLIBIND	Kevin Conway	Negative	View
8	JDRJC Associates	Jim Cyrulewski		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Stacy Dochoda	Negative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

Non-binding Results

Project 2007-03: TOP-001-2

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-03 Non-binding Poll TOP-001-2
Poll Period:	4/11/2012 - 4/23/2012
Total # Opinions:	288
Total Ballot Pool:	373
Summary Results:	77.21% of those who registered to participate provided an opinion or an abstention; 69.84% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	

1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill	Negative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Richard Burt		
1	Muscatine Power & Water	Tim Reed		
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	

1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	Frank F Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	South Texas Electric Cooperative	Richard McLeon		
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Negative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Affirmative	View

2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers	Abstain	
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Negative	View
3	Dominion Resources Services	Michael F. Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Negative	
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	

3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Negative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View
3	Hydro One Networks, Inc.	David Kiguel	Abstain	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	

3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Abstain	

5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Negative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Negative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Abstain	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Affirmative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	

5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti		
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View

6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Affirmative	
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons		
8		James A Maenner		
8		Merle Ashton		
8		Edward C Stein		
8		Roger C Zaklukiewicz	Affirmative	
8	INTELLIBIND	Kevin Conway	Negative	
8	JDRJC Associates	Jim Cyrulewski		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Abstain	

9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Negative	View
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Abstain	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	View
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Stacy Dochoda		
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	View

Non-binding Results

Project 2007-03: TOP-003-2

Non-binding Poll Results	
Non-binding Poll Name:	Project 2007-03 SB Non-binding Poll TOP-003-2
Poll Period:	4/11/2012 - 4/23/2012
Total # Opinions:	289
Total Ballot Pool:	373
Summary Results:	77.48% of those who registered to participate provided an opinion or an abstention; 67.64% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Abstain	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	

NERC

1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Negative	View
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko		
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill	Negative	
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Richard Burt		
1	Muscatine Power & Water	Tim Reed		
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Abstain	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Abstain	
1	Omaha Public Power District	Doug Peterchuck	Negative	
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	

1	Pacific Gas and Electric Company	Bangalore Vijayraghavan	Affirmative	
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	Frank F Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Abstain	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	
1	Sierra Pacific Power Co.	Rich Salgo	Negative	
1	South Texas Electric Cooperative	Richard McLeon		
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	View
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Affirmative	View
2	Independent Electricity System Operator	Kim Warren		

2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	View
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	View
3	Central Lincoln PUD	Steve Alexanderson	Abstain	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Negative	View
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Redding	Bill Hughes	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers	Abstain	
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry		
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	View
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray		
3	Great River Energy	Sam Kokkinen	Negative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	View

3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Abstain	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Abstain	
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Potomac Electric Power Co.	Robert Reuter	Abstain	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Negative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Abstain	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	View
3	Seattle City Light	Dana Wheelock	Negative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Abstain	

4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Abstain	
4	Seattle City Light	Hao Li	Negative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul Cummings	Affirmative	

5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Abstain	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner		
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Negative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Tom Foreman	Abstain	
5	Luminant Generation Company LLC	Mike Laney	Negative	View
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Affirmative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Negative	View
5	Orlando Utilities Commission	Richard Kinas		

5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Abstain	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Abstain	
5	Salt River Project	Glen Reeves		
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Abstain	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles		
6	AEP Marketing	Edward P. Cox	Negative	View
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti		
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	View

6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer		
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View
6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Abstain	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons		
8		Edward C Stein		
8		Merle Ashton		
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8	INTELLIBIND	Kevin Conway	Negative	View
8	JDRJC Associates	Jim Cyrulewski		
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	

10	Midwest Reliability Organization	James D Burley	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B. Edge	Abstain	
10	Southwest Power Pool RE	Stacy Dochoda		
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Abstain	View

Individual or group. (39 Responses)
Name (23 Responses)
Organization (23 Responses)
Group Name (16 Responses)
Lead Contact (16 Responses)
Question 1 (38 Responses)
Question 1 Comments (39 Responses)
Question 2 (34 Responses)
Question 2 Comments (39 Responses)
Question 3 (33 Responses)
Question 3 Comments (39 Responses)
Question 4 (0 Responses)
Question 4 Comments (39 Responses)
Question 5 (24 Responses)
Question 5 Comments (39 Responses)
Question 6 (0 Responses)
Question 6 Comments (39 Responses)

Individual
Joe Couturier
SSOE Group
No
TOP-001-2 Grammatical: R8 and its supporting rationale refers to a term SOL. The term is 'defined' later in R9. The 'definition' should probably be defined at the time of its first usage. R11 The TO directs someone to do something. However, who is directed is not defined. Is it directed to the RC?
Group
Northeast Power Coordinating Council
Guy Zito
No
It is written in FAC-014-2 R5.2: R5.2. The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area. This already mandates that the Transmission Operator provide its Reliability Coordinator SOLs. This requirement and TOP-001 R8 must be made to agree. As explained in the redline version of TOP-001: “Rationale: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.” It is understood that the impacts of some SOLs may attract increased attention because of the operational implications of them being exceeded. It must also be realized that every SOL has a reliability impact. The added wording adds unneeded complication to the Requirement. Will the proposed requirement create a new class of SOLs that might include any that might be “intermittent” in nature, such as those occurring during televised events, etc.? This becomes a moving target, and it may become problematic for keeping track of those SOLs to which these requirements apply, i.e., those that require notification to the Reliability Coordinator, versus those which don’t. Regardless, operator responses to any SOL’s on their systems should be the same in terms of swiftness and a sense of urgency. The phrase “supporting reliability internal” is used in R8. What constitutes “supporting reliability internal”? This may present compliance issues. Experience has shown that the use of the terms internal, external, local, wide area have presented auditing difficulties that generated documentation issues.

TOP-001 uses the term “Reliability Directive” which is dependent on a definition developed in Project 2006-06 Reliability Coordination. Because of the development of this definition in both Projects, NERC should post these projects simultaneously to gain industry support to move these projects forward.
Group
PNGC Group Comments
Ron Sporseen
No
Comments: The PNGC comment group believes there should be a distinction in the “Applicability” section of the standard distinguishing between “Scheduling DP/LSE” and “Non-scheduling DP/LSE”. PNGC members are small rural cooperatives that are “Full service BPA customers.” This means is that BPA is our power supplier and scheduling agent and therefore handles all scheduling, tagging, dispatching of resources and curtailments of load from breakers on BPA’s system for PNGC members. According to a letter from the WECC Reliability Coordinator (VRCC and LRCC) none of PNGC’s members will ever receive a “Reliability Directive”. Such a Directive would be sent to either a Balancing Authority (BA), or a Transmission Operator (TOP). In fact, the Bonneville Power Administration (BPA) is the BA and TOP for many of our members so R1 and R2 are nothing more than a clerical exercise for many DP/LSE entities. We estimate there are over 100 entities that are BPA Full Service customers that are in a similar position and making this standard applicable to them does nothing to enhance reliability. A simple declarative statement in the Applicability section of the standard could focus the intent of the SDT on those entities that need it while lessening the compliance risk and clerical burden for other entities that the standard should not apply to. We suggest: 4. Applicability 4.1 Balancing Authority 4.2 Transmission Operator 4.3 Generator Operator 4.4 Distribution Provider: With Real-time Operations desk 4.5 Load-Serving Entity: With Real-time Operations desk
No
Comments: In addition to the same Applicability argument we made in Question 1 for TOP-001-2, the PNGC comment group has a couple of minor issues with TOP-003-2: 1. We question the Violation Risk Factor (VRF) of “Medium” for R5. R1-4 have VRFs of “Low” so the “Medium” designation for R5 seems unwarranted. If the SDT views the failure of TOPs and BAs to distribute data requests to other entities in an agreeable format as a “Low” risk, then the failure of those other entities to respond to issued data requests should also be a “Low” risk. We believe R1-5 should all have a “Low” VRF. 2. R1 and R2 require the BA and TOP create a documented specification for data needed to perform analysis functions and Real-time monitoring. We question R1.2 and R2.2: “A mutually agreeable format.” There absolutely should be a mutually agreeable format for the data but the standard doesn’t define how that is to be accomplished. It seems to us that the TOP and BA will just issue the directive without consultation and that violation of R1.2 and R2.2 by the TOP or BA is unenforceable. We suggest expanding M1 and M2 to include acknowledgement by entities that are the subject of requests. The acknowledgment should include that the request was received and the data format is agreed to.
This question is a duplicate of Question 2. If question 2 refers to TOP-002-3 then our comments from Question 2 should be in this spot. We have no comments for TOP-002-3.
No
Please see our response to Question 2.
none
Individual
Michael Falvo
Independent Electricity System Operator
Yes

Yes
Yes
Yes
In the Violation Severity Levels section of the standards, items that contain “whichever is less” following the “or” statement, may be difficult to interpret. As a suggestion, this could be addressed by improving the wording, providing examples or categorizing non-compliance as a percentage only (rather than a number “or” percentage, whichever is less)
The proposed effective dates for the TOP-002-3, TOP-003-2 and PRC-001-2 standards conflict with Ontario regulatory practice respecting the effective date of implementing approved standards. It is suggested that this conflict be removed by appending to each of the sentences in Section A5 of both standards, after “following applicable regulatory approval”, to the following effect: “, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.” The places for the insertion are: TOP-002-3, Section A5, end of second sentence TOP-003-2, Section A5, end of second sentence. PRC-001-2, Section A5, end of second sentence.
Group
Southwest Power Pool Regional Entity
Emily Pennel
Yes
Yes
No
SPP RE does not believe TOP-003-2 addresses the requirements in PRC-001.
SPP RE does not believe TOP-003-2 addresses the requirements in PRC-001.
Group
Imperial Irrigation District (IID)
Jesus Sammy Alcaraz
Yes
Yes
Yes
Yes
Yes
Group
Dominion
Connie Lowe
Yes
Yes
TOP-002-3 M2 should be updated to reflect the changes made in R2 (as suggested below). M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL

and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis. VSLs R2 (page 5 redline version) Severe Column should be updated to reflect the changes made in R2 (as suggested below). The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.
Yes
Agree with changes made.
Yes
Implementation Plan – Project 2007-03 Real-time Operations; on pages 1 and 2, instances where TOP-003-1 is mentioned it should read as TOP-003-2.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
Yes
TOP-002-3, R1 TOP-002-3, R1 states “Each Transmission Operator shall have an Operational Planning Analysis …” and the mapping document says that this requirement “is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator.” As such, Austin Energy suggests that the language in TOP-002-3, R1 be changed from “… shall have an Operational Planning Analysis …” to “… shall perform an Operational Planning Analysis ….” This language matches IRO-008-1, R1 and better aligns with Measure 1 for TOP-002-3.
Yes
We agree.
Yes
The VSL for TOP-001-2, R8 includes instruction to “start with the Severe VSL first and then to work your way to the left until you find the situation that fits.” It explains that the goal is to assign a Severe VSL to a small entity who has just one affected reliability entity to inform and fails to do so. This structure usually makes sense; however, it is not applicable to R8. R8 requires the TOP to inform its RC of SOLs that have been identified as supporting reliability. The variability in the requirement is in the number of SOLs identified not in the number of registered entities to inform. The intent of being non-discriminatory by size of entity is already covered with regards to the number of SOLs identified because the VSL uses the “# SOLs or % of SOLs, whichever is less” approach, and the instruction becomes unnecessary. Austin Energy recommends that the SDT remove the instruction statement above R8.
None.
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
Yes
No

Multiple entities commented in the prior round that the standard would expose RE's to violation space in the event of a communications failure. Although the SDT stated in the consideration of comments that "It is not the intent of the SDT that TOP-003-2 penalizes entities for communication errors. The intent is to have the data communications established.", the plain language of the standard is in conflict with this position. The standard as written states a RE "shall satisfy the obligations of the documented specifications for data." Among the specifications of real time data requests are the periodicity of the submission. For example, PJM in Manual 14D, Generator Operational Requirements, states "All data items, regardless of type, are collected and disseminated at the same 2-second rate. Instantaneous MW and MVAR information is collected on the same data scan as Integrated MWh and MVARh." If a RE has a loss of their RTU, they will have failed to "satisfy the obligations of the documented specifications for data", and be exposed to a potential violation. If the intent of the SDT is as stated in the previous consideration of comments, there must be some language to that effect added to the standard. In R1, adding a bullet 1.21 "an alternative format for use in the event of interruption of the mutually agreed format" would close the hole in the language as written and satisfy the stated objections.
Yes. Thank you to the SDT for removing these requirements.
No
As written data transmission failures subject REs to a severe violation in R5, see Q3 response.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
As a GO/GOP, Ingleside Cogeneration LP is subject only to TOP-001-2 R1 and R2, related to compliance with a Reliability Directive. We believe that the SDT has captured the appropriate circumstances for when a Reliability Directive is issued and identified – and the circumstances under which it may be not be possible to accommodate one. Furthermore, we agree with the language added to the corresponding Measures (M1 and M2) specifically allowing an attestation to be supplied to a CEA if a Reliability Directive was not received during the compliance time frame.
Yes
Yes
We are encouraged that the SDT has added a statement in M3 and M4 calling for those TOPs and BAs who post their data specifications to also electronically notify the downstream data suppliers. This is a good first step in the use of a web-based data collection process – which we hope will replace the spreadsheet-based process mostly in place today. A goal of such a system must be to consolidate all operational data requirements into a single template, so that data suppliers are not subject to redundant criteria.
Ingleside Cogeneration LP agrees that relay and equipment status can be included in a telemetry specification as part of TOP-003-2 – which is redundant with PRC-001-1 R2 and R6. Similarly, the coordination of changes in generation operating conditions such as de-ratings that could require changes in the TOP's Protection System (R5) can be captured in existing data submission vehicles that TOP-003-2 will also cover.
Yes
Individual
Rich Salgo
NV Energy
Yes
Yes

Yes
We see no problem with what was changed in this posting; however, please note issues raised related to TOP-003-2 in the comment submitted on Question 6.
No, we believe there may be reliability gaps introduced with the specific deletion of old R2 from PRC-001. We are concerned that the open-ended specification of required data per proposed TOP-003 R1 may not adequately cover the notification of status and conditions for certain protection systems and SPS. With the requirement R2 in place, there is no doubt about the need to make notification of these sorts of losses or status changes. Absent the requirement, it is likely that inconsistent specifications for such information by TOP's or BA's will result.
No
PRC-001 R1: Though this requirement does not appear to be within the scope of the SDT's efforts in this project, we note that for R1 (familiarity of purpose and limitations of protection systems), there is no Measure in the Standard, and the VSL's appear to be quite subjective. I would like to make a specific suggestion, but cannot do so without knowing what sort of Measures are intended for this requirement. Perhaps, change the VSL language to state "Entity does not possess documentation describing purpose/limitations of its protection systems for its Operator personnel."
TOP-003-2 R1-5 1)We appreciate the work of the SDT to allow discretion in the creation of data and information specifications to provide for reliable operation; however, we believe that the open-ended requirements do not provide sufficient clarity about what is expected. This entity is a BA/TOP as well as a GOP, GO, TO, etc. As such, is it the intent of these requirements that we would have to issue a specification to ourselves for the data and information that we are to provide to ourselves? If so, how is this expected to take form? We could envision a document that lists the SCADA RTU points required from every BES station in the footprint, which calls into question what happens when an inevitable SCADA interruption occurs. Is the entity in violation of R5 because for a short period of time it did not satisfy its obligations to provide data under the specification? 2) Or, is it the intent of the SDT that such specifications are issued to "external" entities, such as interconnecting Generators, TOP's within the BA footprint, etc.? 3) On the surface, the open-ended fill-in-the-blank specification requirement seems like a good idea; however, at closer evaluation, we believe it will lead to great inconsistencies without some additional guidance on what needs to be included in the specifications and to whom the specifications should apply.
Group
Progress Energy
Jim Eckelkamp
Yes
: Progress Energy requests the removal of the word “identified” in association with Reliability Directive in all Requirements and Measures. Communications between Transmission Operators and other functional entities already require 3-part communications; having to state ‘This is a Reliability Directive’ to each entity and receive confirmation of that back from each entity, especially across a fleet of Generator Operators and LSEs, could add unnecessary time before action is taken. Entities should always assume that each directive being given to them is a Reliability Directive and respond accordingly. R1 would read “and Load-Serving Entity shall comply with each Reliability Directive issued by its Transmission Operator…”.
Yes
Please change the R2 VSL from “supporting its internal area reliability” to “supporting reliability internal to its Transmission Operator Area…”.
Yes
Individual
Joe Petaski
Manitoba Hydro
No

Manitoba Hydro is voting negative on TOP-001-2 for the following reason: R8 and R9 - In the absence of the rationale box in the final approved version of the standard, R8 is extremely unclear. All SOL's support reliability based on an assessment of operational planning. The requirement (R9) prohibits operation outside any SOL "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based." However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. The term continuous duration is undefined and as such makes the standard subject to interpretation. It would appear that the standard expects the system operator to do something more than would be done for an IROL.
Yes
Section 1.3 Data Retention - For consistency with TOP-001-2, the retention period for voice recordings in TOP-002-3 should be changed from 3 months to 'ninety calendar days'.
Yes
R2.1 - For consistency with R2 and completeness, 'analysis functions' should be added to R2.1. Suggested wording: 'A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring'.
Section 1.4 Compliance Monitoring and Assessment Processes - Section 1.4 should be removed as it is identical to Section 1.2 'Compliance Monitoring and Reset Time Frame'.
Yes
No additional comments.
Individual
Andrew Z. Pusztai
American transmission Company
Yes
Yes
No
Requirement R3 and R4 should specify which entities are required to respond to data requests. For example, a TOP in Indiana who sends a request to a TOP in Wisconsin; should the TOP in Wisconsin be required to respond. ATC recommends that the term "contiguous entity" be referenced and added to the requirements.+
ATC agrees with removing R6 from PRC-001, however ATC does not believe it is appropriately addressed in TOP-003-2. If the intent is to have SPS data as a part of a data specification, it should be stated in the requirements of TOP-003-2.
Group
MRO NSRF
WILL SMITH
No
For R9, the drafting team did not address "continuous duration". Many entities had commented that the term is vague. Is continuous duration, 8 hours or 15 minutes? For IROL limit violations or Unknown State conditions, the entity has 30 minutes to mitigate the situation.
Yes
No
Requirement R3, and R4 must specify which entities are required to respond to data requests. For example should a TOP in Indiana send a request to a TOP in Wisconsin, must it be complied with. Suggest a, "contiguous entity" reference. Requirements R1 and R3 are very vague and need to add more specificity similar to that from existing standard TOP-005 which includes specific guidelines.

The NSRF agrees with removing R6 from PRC-001, however we do not feel it is appropriately addressed in TOP-003-2. If the intent is to have SPS data as a part of a data specification, it should be stated in the requirements of TOP-003-2.
No
TOP-001-2 The adding the language of “or 5% or less of the affected Transmission Operators, whichever is less”, “or more than 5% or less than or equal to 10% of the affected Transmission Operators, whichever is less”, “or more then 10% or less than or equal to 15% of the affected Transmission Operators, whichever is less”, “ or more than 15% of the affected Transmission Operators, whichever is less” to R3, R5, and R6 is confusing and not necessary. For example: 10 affected TOs. The lower VSL states: The TO did not inform one other TO or 5% or less of the affected TOs, whichever is less. 5% of 10 is .5 TOs which is less than 1. The percentage language should be removed. TOP-003-2 – Same issue with VSLs as with TOP-001-2. The percentage language should be removed from R3 and R4. PRC-001-2 – R1 VSL for High and Severe seem arbritary. Not knowing limitations are not as bad as not knowing purpose? Suggest either breakdown by number of systems. Ie: did not know purpose and limitations of 1 protection scheme, etc. Or Binary. Severe – did not know purpose and limitation of protections systems in its area.
Individual
Greg Rowland
Duke Energy
No
While the drafting team has made several improvements to this standard, we believe these additional changes are needed: • The definition of Reliability Directive includes the defined term “Adverse Reliability Impact”, which should be replaced by the actual wording of latest (8/4/2011) BOT-approved definition of “Adverse Reliability Impact”, since it has NOT yet been approved by FERC. • R3 places the responsibility on a Transmission Operator to possess tools it does not currently utilize. Most companies will study their own area and possibly one or two busses out. In order to be compliant to this standard, it would appear a Transmission Operator would need to possess study tools which are currently utilized by the Reliability Coordinator. Suggest considering adopting language where the Transmission Operator requests assistance in identifying impacts outside their direct interconnects. Suggested rewording: “Each Transmission Operator shall work in conjunction with its respective Reliability Coordinator to inform other Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: High] [Time Horizon: Operations Planning,]”. • R4, as written, does not consider an entity that might be under the control of an RTO. A Transmission Operator, as a member of an RTO, cannot take actions without the permission unless during an emergency where cascading outages, loss of equipment etc. is involved. If the event described in R4 as currently written is not an immediate emergency, the Transmission Operator would need to gain permission of the RTO to comply. Suggest wording changes to take into consideration entities whose facilities are under RTO control. Suggested rewording: “Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that appropriate agreements are in place, and the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. In the event the Transmission Operator is under the purview of a Regional Transmission Organization (RTO), the Reliability Coordinator of the RTO shall work with its Transmission Operators in requesting available emergency assistance. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]”. • R5 – Similar comment to R3. This requirement places the responsibility on a Transmission Operator to possess tools it does not currently utilize. Most companies will study their own area and possibly one or two busses out. In order to be compliant to this standard, it would appear a Transmission Operator would need to possess study tools which are currently utilized by the Reliability Coordinator. Suggest considering adopting language where the Transmission Operator requests assistance in identifying impacts outside their direct interconnects. Suggested rewording: “Each Transmission Operator shall inform its Reliability Coordinator, who shall assist in identifying other Transmission Operators of its operations that are known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations include but are not

limited to relay or equipment failures, and changes in generation, Transmission, or Load. [Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]”. • R6 – Strike the word “negatively”, since no one will be “positively” impacted. • R6 needs to be clarified as to the intent. Does registered entity mean the corporation, or does registered entity mean a TO, BA etc. Suggestion would be to remove NERC registered from the language. • R8 – The SDT has included a Rationale for SOLs that deserve increased attention. Several examples cited in the Rationale are for service to local load, and while the local loads may be important loads, the associated SOLs would have no impact on BES reliability. R8 requires the TOP to inform the RC of such SOLs, and we question why the RC needs to be informed of SOLs that only impact service to local loads. We believe that the phrase “supporting its internal area reliability” should be further clarified in some way. The inclusion of the undefined concept of “supporting internal area reliability” creates undue compliance risk, since auditors could potentially find an entity non-compliant if no SOLs have been identified as “supporting its internal area reliability”. With no clarification, it is conceivable that every SOL on a TOP’s system could be considered to support its “internal area reliability”. Communicating all SOLs would inundate the RC with unneeded information, which we believe would be detrimental to reliability. If this requirement stays in the standard, it needs to be reworded to indicate that any SOLs identified are identified at the sole discretion of the TOP. • R8 - Change the phrase “as supporting” to “in support of”. • R9 – Strike the word “would” and add an “s” to “cause”.
No
• R2 – Consistent with our comment above on TOP-001-2 Requirement R8, the phrase “supporting its internal area reliability” should be further clarified in some way. Also, change the phrase “as supporting” to “in support of”.
Yes
Yes
No
• TOP-001-2 VSLs should be revised consistent with our comments on the requirements. • TOP-003-2 VSLs have explanatory language on how the SDT intends the VSLs to be used. This language needs to be incorporated into the VSLs more directly, because compliance personnel will not be bound by the SDT’s intent.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Yes
Yes
Yes
Yes, we agree with the changes the drafting team has made.
Yes
none
Individual
Keira Kazmerski
Xcel Energy
No
R8 – Please clarify the difference between R8 of TOP-001-2, and R2 & R5 of FAC-014-2. We would expect in some regions, depending on the RC’s SOL methodology, that this would be the same information. For example, in SPP, all Facility Ratings are considered SOLs. Compliance with R9 of TOP-001-2 will prove quite difficult in regions like this. Please clarify the what the drafting team envisions being the difference between these two standards, and what is expected to be given to the

RC under each. R9 - We appreciate the drafting team's efforts. However, we are still concerned that R9 will not allow the Transmission Operator the flexibility to identify the best SOL recovery approach, without incurring a violation of the requirement. Instead, the TOP may be forced to shed load in order to avoid violating the requirement. This is not ideal, especially when the situation could be mitigated successfully with alternative measures. It is not clear if an entity is allowed to use an RC-approved contingency plan to mitigate a situation that would cause a Facility Rating violation (i.e. the Facility Rating is the SOL), without also incurring a violation of R9. To further explain, if an entity foresees exceeding an SOL in its OPA, and obtains approval from the RC on their proposed contingency plan (which includes a Facility Rating violation), will that entity be considered in violation of R9 once the exceedance occurs and the contingency plan is implemented?
Yes
Yes
Group
Southern Company
Antonio Grayson`
Yes
R3. The requirement is worded such that it implies that the Transmission Operator has a Transmission Operator. We suggest adding the word "other" so that it reads "shall inform its Reliability Coordinator and other Transmission Operator(s)…." R5. We recommend the following word changes: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations that are known or expected to result in an Adverse Reliability Impact on those their respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations may include are relay or equipment failures, and changes in generation, Transmission, or Load.
No
R3- Southern understands the intent of this requirement is to notify all registered entities that may be affected by a mitigation plan for the next day so they can be prepared to respond. However, in some cases like the one shown in the example below, it is unreasonable to expect the TOP to notify every GOP that could be re-dispatched. Requiring this would actually put the system at risk as the TOP would be focused on notifying GOPs inside its TOP area and potentially outside its TOP area and not focused on operating the system. Southern suggests that the requirement be changed to state that the TOP will notify "other TOP's and associated RC(s) associated with actions in the plan(s)" in a similar manner that other TOPs and RCs are notified in the proposed TOP-001-2, R3 and R5. If that is unacceptable to the SDT then it is suggested at a minimium that "all NERC registered entities" be clarified with the addition of the word "explicitly" just prior to" identified in the plan(s)". Example: An SOL is identified in the Operational Analysis for the next day from R2. The plan to mitigate this SOL is to call an IDC-TLR. The level of the TLR may or may not reach level 5. If the TLR reaches level 5 many generators will be required to be re-dispatched inside and outside of the TOPs area. This requirement will require the Transmission Operator to notify every Generator Operator that could possibly be re-dispatched for a TLR-5. Another concern with having the TOP notify all entities (which would include those outside their area) is the added FERC Standards of Conduct risk that the NERC standard is forcing the TOP to assume. For example, notification may go to a GOP which also performs market functions about which the TOP is unaware. In communicating the plan to the GOP, the TOP may inadvertently communicate non-public transmission information in violation of the Standards of Conduct. If communications is limited to external entities that are TOP and RC, this risk is eliminated and the communication to the GOP will take place by its native TOP - which should be familiar with any Standards of Conduct restrictions on communication to the GOP.
Yes

Yes, we agree with the SDT's suggestion
Yes
Individual
Larry Raczkowski
FirstEnergy Corp
Yes
Yes
Yes
FE agrees with the changes that have been made by the drafting team.
Yes
FE appreciates the hard work of the drafting team and for addressing our concerns from the previous ballot.
Individual
Terry Harbour
MidAmerican Energy
No
NERC standards cannot be vague and undefined or NERC interprets the standard and creates new requirements through the Compliance Application Notice process. The rational specified for R8 shows that R8 deals with a Transmission Operator defined special subset of SOLs. However, the current wording in R8 does not use the wording “special subset of SOLs as defined by the TOP”. The standard uses “as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis”. This is not clear enough for a black and white compliance audit and therefore is inadequate. Further in R9 continous duration remains undefined. Therefore, specific wording needs to be added to show that R9 applies to the “special subset of SOLs with there corresponding continous duration timeframes as defined by the TOP” Last, the the same wording and definition must be applied to FAC-011-2 R2 to remain consistent and clear.
No
TOP-002 R2 uses the same vague language as TOP-001 R8. The wording “special subset of SOLs as defined by the TOP” needs to be added. Otherwise NERC and regional auditors will apply the wording broadly when the intent was for a specific subset of SOLs defined by the TOP. Also see the NSRF comments
No
See the NSRF comments
Yes - retire the three requiements in PRC-001
No
See the NSRF comments
Group
Idaho Power Company
Molly Devine
No
I don’t think that this requirement should be retained. With e-tag requirements, mid-hour scheduling and the ability to process an emergency tag at any time it seems like an interchange. What is emergency assistance?
Yes

I agree with the direction of the project. Consolidating all the TOP standards and eliminating the redundancy will make it much easier.
No
TOP-003 will require that we create a list of data necessary to complete our operational planning analysis. Currently I don't think we have a good process for doing analysis so defining the data required may be difficult.
Yes
Group
Luminant
Brenda Hampton
Yes
Yes
No
TOP-003-2 as currently written does not provide any recourse for the entity receiving a data request if that entity feels the data request is unreasonable either in content or timing or if the entity does not have the data available to submit. As such I would recommend modify R5 as follows: R5. Each......shall satisfy the obligations of the documented specification for data. R5.1. If the entity receiving the data request cannot provide the requested data either in content or timing then the entity receiving the data request shall notify the requesting entity and provide a reason for not providing the data.
No
The VSL for TOP-003-2 R5 places a more stringent severity level on the entities receiving the data requests than it places on the entities that are responsible for creating the data requests. As such, I would suggest changing the VSL for TOP-003-2 R5 to the following: Lower: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy one of the obligations of the documented specification for data Moderate: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy two of the obligations of the documented specification for data High: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy three of the obligations of the documented specification for data Severe: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy four or more of the obligations of the documented specifications for data.
Individual
Texas Reliability Entity
Texas Reliability Entity
No
1) Definitions: Texas RE does not agree with the proposed definition of “Reliability Directive” and encourages the SDT to look past a compliance based outlook regarding the word “directive”. If there is no Reliability Standard support for use of directives to AVOID emergencies, emergencies will continue to occur. Consider using the broader defined term “Operating Communication” from COM-003 rather than “Reliability Directive” in this standard. 2) R1: This requirement, as written, states that the BA, GOP, DP, and LSE must comply with Reliability Directives, which, by definition, are only issued in Emergencies or to prevent instability or Cascading. There is not a requirement in the TOP or IRO standards that obligates a Registered Entity to comply with other directives issued by the TOP or RC used in operating the grid in a reliable manner. For example, some generator operators exceed the operating basepoint that is communicated to the unit by the ISO, which creates congestion and overloads the transmission system. Under the proposed R1 language, there is no requirement for an entity to comply with this type of directive, since it is not a “Reliability Directive” until an Emergency

occurs. 3) R3: Requirement R3 seems to be missing some words. It doesn't say WHAT the TOP should inform other entities about. Also, it is not clear if this requirement is supposed to be about planning ("expected to be affected by anticipated Emergencies") or real-time operations ("known to be affected by actual Emergencies") or both. If the latter is intended, the Time Horizon should include Real-Time Operations and Same Day Operations. We suggest changing the language to "Each Transmission Operator shall inform its Reliability Coordinator and other affected Transmission Operator(s) about each actual or anticipated Emergency , which may be determined in Real-time or based on its assessment of its Operational Planning Analysis" 4) R4: Reinsert Generator Operator applicability from old R6. The stated reason for removal of Generator Operator is incorrect and violates the Functional Model which states that a Balancing Authority may direct "resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time" and "direct "Generator Operators to implement redispatch for congestion management". Both of those type actions may include rendering emergency assistance. 5) R5: The requirement implies, but does not specifically state a time frame for informing the RC. The RC must be informed in sufficient time in order to respond to the system condition. The phrase "unless conditions do not permit" is ambiguous and should be made more definite. We suggest rewriting R5 as follows: "Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas within a timeframe that is sufficient for the RC and affected Transmission Operators to respond to the system condition, unless communication capabilities have failed." The Time Horizon should also include Operations Planning since the Requirement language includes "known or expected." 6) R6: There is a need to include Generator Operator in this requirement. There is no clarification in the mapping document regarding the loss of the applicability to the Generator Operator (previously in TOP-001-1 R3). 7) R8: This requirement, as written, states that the TOP must inform the RC of SOLs based on its assessment of its Operational Planning Analysis, which, by definition, is an analysis for the next day's operation that may occur either a day ahead or as much as 12 months ahead. SOL violations can occur in Real-Time (e.g., transmission thermal limit violations, voltage violations, etc.) due to forced outages from storms or equipment failures that may not have been studied under the Next-Day analysis and various other real time conditions. We suggest rewording the requirement to read "Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based ON ANTICIPATED OR ACTUAL EMERGENCIES OCCURRING IN REAL-TIME OR BASED on its assessment of its Operational Planning Analysis." It is important to recognize the Real-Time issues because several of the Requirements following Requirement 8 refer to SOLs "identified in Requirement R8." Additionally, since the definition of SOL includes post-contingency criteria, contingencies are not limited to Operational Planning Analysis timeframes. The VSL language also needs to accommodate Real-Time considerations. 8) R9: See our comment regarding R8 – there is a reliability gap because SOLs identified in Real-Time (as opposed to those identified in the Operational Planning Analysis timeframe) are not included. 9) R10: See our comment regarding R8 – there is a reliability gap in the actions needed to return the system to within limits for SOLs identified in Real-Time as opposed to those identified in the Operational Planning Analysis timeframe. 10) R11: See our comment regarding R8 – there is a reliability gap for SOLs identified in Real-Time as opposed to those identified in the Operational Planning Analysis timeframe. 11) What is the intended difference between "TOP shall not operate outside any SOL" in R9 and "TOP shall act or direct others to act to mitigate both the magnitude and the duration of exceeding . . . an SOL" in R11? The same action or inaction would likely result in violations of both requirements, resulting in a "double-jeopardy" situation.
Yes
No
1) Overall, this change to TOP-003-2 will cause differences in what each TOP/BA thinks it needs in terms of data, which will be difficult to audit. There should be a minimum set of data that the TOP/BA should address (especially when removing more specific Requirements such as those that are deleted from PRC-001-1.) For example, if a TOP or BA decides not to monitor its SPSs, which is currently required by PRC-001-1, there will be no repercussions from a compliance standpoint, but an impact to monitoring the state of reliability will occur. 2) R1: We suggest adding "analysis functions" after Operational Planning Analysis to fully capture performance requirements for a TOP during Real-Time. 3) R2: We suggest adding "Operational Planning Analyses" in front of "analysis functions". The

Operational Planning Analysis, by definition, includes “Expected system conditions such as load forecast(s), generation output levels . . .,” which relate to the Real Power balance requirement that the BA must comply with. A BA should also create a documented specification for the data necessary for it to perform an Operational Planning Analysis, which may include development of integrated operational plans, acquiring reliability-related services from Generator Operators, providing generation dispatch to the Reliability Coordinator, and other responsibilities as dictated by the Functional Model. 4) R3 We suggest adding “analysis functions” after Operational Planning Analysis to fully capture performance requirements for a TOP during Real-Time. 5) R4: We suggest “Operational Planning Analyses” in front of “analysis functions” to be consistent with our comment that R2 should require “Operational Planning Analysis” data in the BA’s data specification. 6) R3 and R4: What is the required time frame required for the TOP and BA to distribute changes to its data specification? We suggest adding a sentence that the TOP or BA must distribute its data specification within 30 calendar days of creation or revision. 7) R5: What is the required time frame for an Entity to satisfy the obligations of the data specification? None is specified. We suggest a time frame of 30 calendar days from the date of receipt to comply with changes to data specifications. 8) The VRF and VSL justification document was inconsistent and unconvincing in several respects related to TOP-003-2 R2. That should be revisited after the requirements are firmed up.
No. 1) Requirements R2, R5 and R6 of PRC-001-1, which are proposed to be deleted, are not actually replaced by any new or revised requirements in other standards, resulting in reliability gaps. The PRC-001-1 requirements relate to Same-day and Real-time Operations, whereas the TOP-003-2 requirements relate only to the Operations Planning time horizon. The real-time elements of the PRC-001-1 requirements are lost. 2) R2- Removal of R2 assumes that the requirement intent will be included in TOP-003-2 R1 or R2 specification, but there is no new requirement to replace R2 of PRC-001. 3) R2 – The requirements to “take corrective action as soon as possible” are extremely important to the reliability of the system and deleting them introduces a reliability gap. In the Issues Database document there is indication that R5 of TOP-001-2 satisfies the need for corrective action as soon as possible with the following phrase “Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations.” However, the text of TOP-001-2 R5 does not actually support this approach and therefore leaves a reliability gap in the Standards. 4) Texas RE disagrees with several of the PRC-001 issues listed as complete in the Issues Database. The referenced TOP Standards are extremely limited in scope and lacking in details (especially in light of ignoring Real-Time issues) and are not considered interchangeable with the deleted PRC-001 Requirements as suggested. 5) R5- Removal of R5 assumes that the requirement intent will be included in TOP-003-2, but there is no new requirement to replace R5 of PRC-001.. R5 is related to the coordination of changes affecting protection systems of others. R5 should not be removed because it deals with coordination issues and not merely specification and provision of data. 6) R6—We object to the proposed removal of R6 because this Real-time requirement is not picked up anywhere else, and elimination of the requirement to monitor and communicate the status of Special Protection Systems will cause a reliability gap. 7) There are no Measures for Requirements R1 and R3.
No
1) VSL for TOP-001-2 R3: Operational Planning Analysis, by definition, excludes Real-Time issues such as “actual Emergencies.” We suggest improving the requirement as discussed above and then making conforming revisions to this VSL. 2) VSL for TOP-001-2 R5: “When conditions permit” is subjective and ambiguous therefore consistency in auditing will not occur. Are you sure that “whichever is less” is what you mean to say here? (also applies to VSLs for R3, R6 and R8) 3) TOP-001-2 R7: VRF justification statement is incomplete (“The requirements are viewed as similar since they both refer to <missing text>”) 4) TOP-001-2 R8: In the VRF justification, the text in the second and third bullets appears to be garbled. 5) TOP-001-2 R9: We recommend this requirement be assigned a “High” VRF. Uncorrected SOL violations could cause bulk power system instability, separation, and or cascading if exacerbated in Real-Time by other SOL violations, contingencies, faults, or misoperations (and may be dependent on the SOL Methodology timing in FAC-011 and not be captured in TOP-001-2 R7). Note that the VRF justification for R10 correctly refers to a High VRF for R9. Additionally, remove the word “local” in all places used in the R9 VRF justification.
In the Implementation Plan: 1. The Prerequisite Approvals must include COM-002-3 Communication and Coordination, as that is the source of the proposed definition for “Reliability Directive.” 2. The “Effective Date of Revised Standards” does not match the “Effective Date” within TOP-003-2. 3. The difference between “10 months” and “12 months” will either be (a) no difference or (b) a 3-month

difference, since the effective date of each requirement will fall on the first day of the following calendar quarter. Additionally, since there are no time limits included in the TOP-003 requirements, the reason for the intended timeline differential (2 months) is not supported and arbitrary. We suggest having one effective date for all requirements, and providing clear time requirements for issuing data specifications and submitting responses.
Individual
Darryl Curtis
Oncor Electric Delivery
No
“Oncor respectfully takes the position that the proposed language in R6 will not provide a coordinated communication effort in the event of a planned outage of telemetry, control equipment and associated communication channels. The term “negatively impacted interconnected registered entities” is too broad and too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity."
No
Oncor respectfully takes the position that the language as proposed in R3 places the Transmission Operator in a position of having to determine who or who is not NERC Registered. Oncor agrees that the Operational Analysis Plan should be properly communicated, but that it should not be the role of the Transmission Operator to determine who is or who is not NERC Registered.
Yes
Agree with changes
No
For TPL-001 “Oncor respectfully takes the position that the proposed language in R6 will not provide a coordinated communication effort in the event of a planned outage of telemetry, control equipment and associated communication channels. The term “negatively impacted interconnected registered entities” is too broad and too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity."
No further comment
Individual
Eric Salsbury
Consumers Energy
No
The Reliability Directive definition is not strong enough and leaves too much to interpretation. We feel that the other requirements and items in the standard are acceptable and we could support this version if the definition had more clarity.
No
This standard gives the TOP more direct authority than is in the MISO process today. The market has means to accommodate this operation. In R3, this may conflict with the present logic our TOP follows concerning their operation in the area of communicating conditions to Generation Operators and other Market Participants. We do not support this standard as written.
No
The standard as written is more vague than the current TOP-003. It follows the logic of IRO-010 and talks about specification documents instead of actions that need to be taken. We do not support this standard as written.
The standards that are in place and active clearly define what needs to be done for the reliability of the system. These new standards are designed to make auditing easier. This should not be the goal of these documents. The current active documents do not need to be changed.
Group

SPP Standards Review Group
Robert Rhodes
Yes
Yes
Yes
No (The Yes/No boxes weren't on the screen. All I got was the comment box.) Deleting the requirements from PRC-001 and including them in R1 and R2 of TOP-003-2 raises the question of what other types of data or information need to be included in the specification that do not normally come to mind when considering this type of information. To be sure that all the bases are covered, we would suggest that the SDT provide a guideline which incorporates the types of data and information they envisioned when drafting these requirements. Additionally, incorporating protective relay information in the data specifications of R1 and R2 raises the potential for auditors to question the contents of an entity's specification. Again, guidance is needed on the part of the TOP and BA in developing the specification initially. Could the SDT provide this initial guidance, or list of examples, in the form of a guideline? Also, measures for R1 and R3 are missing.
Yes
TOP-001 – While we agree with what we believe to be the intent of R9, using the word 'continuous' without sufficient context remains ambiguous so as to prevent clear interpretation by all parties. We would suggest replacing the word 'continuous' in R9 with 'applicable'. The timing criterion associated with an SOL should be associated with the timing criterion of the Facility Rating or Stability criteria. The revised requirement would read: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for the applicable duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. TOP-003 – We have concerns with R1 and R2 being as open-ended as they are, especially since they are followed by the obligation to provide that data contained in R5. For example, how do you resolve issues when a mutual agreement cannot be reached? If an entity feels that the requestor is asking for data that goes beyond what they would reasonably need to perform their analysis, what process is used to resolve the stand-off?
Group
Western Eledtricity Coordinating Council
Steve Rueckert
Yes
I support the language of the VSLs for the proposed standards. I also understand the logic behind the statement included above the VSLs for R8 of TOP-001 and R3 and R4 of TOP-003. However, I question whether or not it is appropriate for this type of language to appear in the VSLs. It seems that this should be handled by the Regional Enforcement departments.
Group
Florida Municipal Power Agency
Frank Gaffney
No
The existing TOP-001-1 R7 essentially requires communication to the RC and neighboring TOPs any time a Facility is to be switched. The new TOP-001-2 R5 will only require such communication when such switching would result in an "Adverse Reliability Impact" defined as: "The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled

separation or cascading outages that affects a widespread area of the Interconnection." This significantly reduces the requirements for communication / notification for switching Facilities. It is worthwhile to communicate switching of some Facilities whether or not they would result in an "Adverse Reliability Impact". Suggest rephrasing to something like any unplanned switching of Facilities not "noticed" through data provision of TOP-003-2. With the number of human error events that have occurred, we should not be reducing the communication / notification requirements. R8 is not needed since it is already covered in FAC-014-2 R5.2. As a result, R9, R10 and R11 ought to be modified to refer to FAC-014-2 rather than R8.
No
The existing TOP-002-2 requires that both the BA and TOP perform current day, next day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". FMPA is aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. IN the meantime, the new TOP standards should include operational planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. FMPA believes that both current-day and seasonal remain important, to cover changes from yesterday’s plan (e.g., unplanned outages that have occurred since yesterday’s plan), and to coordinate planned outages seasonally. R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2.
No
Related to the BA performing a day-ahead plan discussed in FMPA’s response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc.” (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.
Please see response to Question 6
While FMPA agrees with a results-based approach to standards, it seems to us that there have been a number of human-error based problems that justify agreed upon protocols and procedures being covered by the standards. Hence, TOP-004 R6, which requires development of formal policies and procedures among neighboring TOPs should not be eliminated from the standards. On the Mapping Document, TOP-004-2 R5, on the discussion that the requirement be deleted, the document says that

the TOP does not have the authority to unilaterally separate without the approval of the RC. FMPA believes that they do if there is an imminent threat (e.g., the exceptions to IRO-001-2 of “unless such actions would violate safety, equipment, or regulatory or statutory requirements”). So, while FMPA agrees that the requirement can be deleted, the reason for the deletion does not seem accurate.
Individual
Randall McCamish
City of Vero
No
The existing TOP-001-1 R7 essentially requires communication to the RC and neighboring TOPs any time a Facility is to be switched. The new TOP-001-2 R5 will only require such communication when such switching would result in an "Adverse Reliability Impact" defined as: "The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection." This significantly reduces the requirements for communication / notification for switching Facilities. It is worthwhile to communicate switching of some Facilities whether or not they would result in an "Adverse Reliability Impact". Suggest rephrasing to something like any unplanned switching of Facilities not "noticed" through data provision of TOP-003-2. With the number of human error events that have occurred, we should not be reducing the communication / notification requirements. R8 is not needed since it is already covered in FAC-014-2 R5.2. As a result, R9, R10 and R11 ought to be modified to refer to FAC-014-2 rather than R8.
No
The existing TOP-002-2 requires that both the BA and TOP perform current day, next day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". FMPA is aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. IN the meantime, the new TOP standards should include operational planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. FMPA believes that both current-day and seasonal remain important, to cover changes from yesterday’s plan (e.g., unplanned outages that have occurred since yesterday’s plan), and to coordinate planned outages seasonally. R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2.
No
Related to the BA performing a day-ahead plan discussed in FMPA’s response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data

specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.
Please see response to Question 6
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Individual
J. S. Stonecipher, PE
Beaches Energy Services of theCity of Jacksonville Beach, Florida
No
The existing TOP-001-1 R7 essentially requires communication to the RC and neighboring TOPs any time a Facility is to be switched. The new TOP-001-2 R5 will only require such communication when such switching would result in an "Adverse Reliability Impact" defined as: "The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection." This significantly reduces the requirements for communication / notification for switching Facilities. It is worthwhile to communicate switching of some Facilities whether or not they would result in an "Adverse Reliability Impact". Suggest rephrasing to something like any unplanned switching of Facilities not "noticed" through data provision of TOP-003-2. With the number of human error events that have occurred, we should not be reducing the communication / notification requirements. R8 is not needed since it is already covered in FAC-014-2 R5.2. As a result, R9, R10 and R11 ought to be modified to refer to FAC-014-2 rather than R8.
No
The existing TOP-002-2 requires that both the BA and TOP perform current day, next day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". We are aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. In the meantime, the new TOP standards should include operational planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal

assessments and focuses only on next-day. We believe that both current-day and seasonal remain important, to cover changes from yesterday's plan (e.g., unplanned outages that have occurred since yesterday's plan), and to coordinate planned outages seasonally. R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2.
No
Related to the BA performing a day-ahead plan discussed in FMPA's response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.
Please see response to Question 6
While we agree with a results-based approach to standards, it seems to us that there have been a number of human-error based problems that justify agreed upon protocols and procedures being covered by the standards. Hence, TOP-004 R6, which requires development of formal policies and procedures among neighboring TOPs should not be eliminated from the standards. On the Mapping Document, TOP-004-2 R5, on the discussion that the requirement be deleted, the document says that the TOP does not have the authority to unilaterally separate without the approval of the RC. We believe that they do if there is an imminent threat (e.g., the exceptions to IRO-001-2 of "unless such actions would violate safety, equipment, or regulatory or statutory requirements"). So, while we agree that the requirement can be deleted, the reason for the deletion does not seem accurate.
Individual
Gregory Campoli
New York Independent System Operator
No
The SDT did not provide reasonable assurance that documented determination of 'Reliability Directive' identification was sufficient to meet R1, in the absents of explicit identificaation during every verbal communication. We believe it is not clear to an auditor that written procedures would be an adequate level of 'identification. A possible solution would be to add R1.1 and spell out that identification of Reliability Directive shall be communicated through approved procedures or verbal identification. In addition, Requirement 11 gives the TOP the authority to "...act or direct others to act..." to mitigate IROL and certain SOL exceedances. Is it the intent of the SDT that the TOP can direct any of the entities to which this standard is applicable? Also SDT should consider a change to say "... act or issue a Reliability Directive to ....' This ties the requirement back to R1 with an obligation to complete the directive. The NYISO is also concern with the use of the definition of 'Reliability Directive' that has not been approved. We recommend balloting TOP-001 simultaneously with the RC Project that includes the definition. As it stands we support the proposed definition. The NYISO suggest
Yes
Yes
TOP-001 R6 What is the difference between "negatively impacted interconnected NERC entities" and "affected entities"? Are both of these the entities for which this standard is applicable?

Individual
Patrick Brown
Essential Power, LLC
Yes
Yes
Yes, I support the recommendation.
Individual
Tony Jankowski
Wisconsin Electric Power Company
No
The SDT's response for previous comments on R6 is that "The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. " If that is the intent of the requirement then the requirement should state that. Also, "negatively impacted" needs to have some sort of bounds. Loss of $1 in revenue is a negative impact.
Individual
Kathleen Goodman
ISO New England Inc
Yes
Vote Your Affirmative vote has been recorded. Ballot Project 2007-03 SB TOP-001-2 March 2012_in Description Project 2007-03 SB TOP-001-2 March 2012 Vote Affirmative Comment TOP-001 Standard uses an undefined term "Reliability Directive" which is being proposed in the Reliability Coordinator Standards project. We believe that NERC should post these inter-related projects simultaneous in order to achieve industry support to move these important projects forward. If the RTO Project is approved, it should only be presented to the BOT simultaneously with an approved RC Standards project. Additionally, if the definition of "Reliability Directive" is modified in any way in the Reliability Coordinator Standards project, this would be a material change to this standard and could result in company's filing comments in opposition to FERC.
Yes
Yes
Individual
Brian J Murphy
NextEra Energy, Inc.
Yes
Yes

Yes
NextEra believes additional editing is needed to provide the step-by-step clarity the proposed Reliability Standard seeks to implement. To provide more clarity, NextEra suggests that in R3, R4 and R5 be rewritten as follows: “R3. Consistent with the requirements of R1, each Transmission Operator shall distribute its request for data to each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider that has data required to be used in the Transmission Operator’s Operational Planning Analysis and Real-time monitoring process. “ “R.4 Consistent with the requirements of R2, each Balancing Authority shall distribute its data request to each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider that has data required to be used in the Balancing Authority’s analysis functions and Real-time monitoring process.” “R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider that receives a data request pursuant to Requirement R3 or R4 shall provide the requested data.”
Yes, we agree.
Yes
Individual
Russell A. Noble
Cowlitz County PUD
Yes
Yes
This Standard is not applicable to Cowlitz PUD and the District will abstain in the ballot. However, this commenter sees no problems with the changes.
No
After reviewing the industry comments submitted, Cowlitz is respectfully perplexed why comments were not addressed related to lack of recourse the receiving entity of a data specification has if the data specification is unreasonable. The data specification receiving entity must have some recourse to appeal unreasonable obligation requirements short of appealing a violation finding through the RE/NERC/FERC or ultimately a court of law. Due to the undefined nature of what constitutes a reasonable data specification document other than a “mutually agreeable format,” the risk of capricious dictatorial demands having no reliability return is high. The usage of “format” can only encompass the organization, plan, and style of the data to be submitted; this can’t be used to limit data submittal to that which is available at a rate of transmittal which is possible. Cowlitz can’t find a remedy for requirement R5 without allowing for some risk of entity intransigent behavior leading to RE or ERO intervention. However, there are current standards that allow, but limit, this risk by defining allowable exceptions. Examples which include such exceptions to requirements are “unless such actions would violate safety…,” contained in several standards; and “unless it provides a reliability reason to the requestor…,” contained in Standard IRO-006-5. Cowlitz suggests the following exemptions: Unless data or information is not available without installation of additional equipment, or can’t be reasonably available due to existing equipment limitations, available personnel limitations, or unexpected equipment failure.
Cowlitz supports the retirement.
No
After reviewing the industry comments submitted, Cowlitz is respectfully perplexed why comments were not addressed related to the VSL binary treatment of R5. A data specification document may be very complex, and the Standard does not define non-compliance other than obligations were not satisfied. One data variable missing (either accidental omission or inability to provide) can incur an immediate violation if the data specification document does not include any leniency in this regard. Further, the proposed VLS for R5 does not allow for any credit of the entity’s effort in fulfilling the

obligations set forth in a data specification document.
It may be best to treat the data specification documentation as an agreement between entities where authorizing signatures from both entities are required to make the agreement effective.
Group
Bonneville Power Administration
Chris Higgins
No
BPA does not believe that the drafting teams' consideration of our previously submitted comments during the last round was adequate. The response appeared to be based on the assumption that the SOL or IROL was based on a thermal limit, not a stability limit. Since a system can go unstable in less than 1 second, the drafting team's response that, "ratings include the qualifiers of time..." did not make sense to us in the context of a "stability limit". As stated in BPA's previous comments, it takes a definite amount of time to readjust the system (change schedules, move generation, or perform other actions) in order to get actual flows down to reliable operating limits when flows have exceeded limits. The standards need to clearly articulate how much time the responsible entities have to accomplish this. The current standard TOP-004-2, R4 clearly articulates a 30 minute rule for this. TOP-001 needs to do the same, especially if TOP-001 will replace TOP-004-2. Previous Comments: Given the potential uncertainty regarding the 30 Minute Rule, BPA suggests adding more clarity to the standard TOP-001-2 as the new draft could be interpreted to mean that one would need to get the flows below the SOL immediately. BPA believes this is not practical because it takes a definite amount of time to change schedules, move generation, or perform other actions in order to reduce loadings on facilities. BPA believes the new draft should include guidance as to how much time the BA or Transmission Operator would be allowed in order to reduce flows when there is an SOL violation. BPA suggests that more clarity be provided and/or the 30 minute rule be added back to the standard. Additional New Comments: TOP-001 introduces a new term and definition, Reliability Directive. This term is used in R1 of the standard in conjunction with two other defined terms, 'Emergency' and 'Adverse Reliability Impacts'. The time horizon described for R1 is 'Operations-Planning'. The timeframes for which this standard applies are 'Operations-Planning', 'Same-Day Operations' and 'Real-Time'. However, if we review the definitions associated with 'Emergency' and 'Adverse Reliability Impacts', it is clear that these terms are used for events that occur only during real time operations. BPA recommends that R1 be re-worded so that the Time Horizons are consistent with the terms used in the standard; that the Reliability Directive definition be clarified so that the timing of the directive is identified; and that use of the terms 'Emergency' and 'Adverse Reliability Impact' be consistent with their definitions, and the 30 minute rule for getting actual flows back within a reliable limit be inserted. BPA recommends that the applicability of R6 be expanded to also include Generation Operators. The intent of this requirement is for those entities with "telemetering equipment, control equipment and associated communications channels" to coordinate outage of such equipment with its Reliability Coordinator and negatively impacted interconnected NERC registered entities. Though Generation Operators have such equipment, as written, this requirement does not require that the coordinate such outages in the same manner as Balancing Authorities and Transmission Operators are required to under this requirement.
No
BPA appreciates the drafting team's response to our previous comments and recommends additional clarification: Previous Comments: Given the potential uncertainty regarding how many day ahead studies may be required, BPA suggests adding more clarity to the standard TOP-002-3 to address. BPA recognizes that various regions experience peak operations at different times of the day, anticipated generation patterns shift over the course of the day; and transmission facilities of service start and stop times associated with planned maintenance and construction work at various times throughout the day. Hence, due to these multiple shifts in forecast system conditions, it is unclear whether more than one study is required to meet the requirements of this standard. Additional New Comments: Many entities tend to perform system studies more than one day ahead. Please specify the threshold at which a prior study would have to be updated to meet the next day study requirement. BPA suggests alternate language for the requirement ...something along the lines of ... An entity or TOP may perform a study more than one day in advance; they shall update the study if system conditions (such as line outages, etc.) changed such that there was more than a 5% change in the system operating limit, thereby requiring the need to rerun the study.

Yes
BPA is in support of this standard due to the importance of being able to receive data.
Yes, BPA is in support of the retirement of the three requirements in PRC-001 as the SDT is suggesting.
TOP-001-2 VRFs/VSLs – NO - BPA recommends a sliding scale based on duration and percentage of the SOL violation. Example: If an entity is high by 2% of the SOL for 1 minute, their VSL should be substantially lower than if they were 25% off for more than 30 minutes. Sliding scale should start at the bottom … couple of MW for a minute … as an example. TOP-002-3: VRFs/VSLs – NO – BPA recommends a sliding scale based on how far off the original study was from the after the fact analysis. Example: If an entity did not have a study, the penalty should be severe. If an entity did have a study, but it was only 5% off, the penalty should be less severe. TOP-003-2 VRFs/VSLs – YES - BPA is in support.
Group
Kansas City Power & Light
Michael Gammon
No
Continuous duration" in R9 is not a defined term and will cause uncertainty and debate under audit as to what time frame this represents. Recommend R9 be modified to reflect the time basis established through the methodology to develop the SOL for the applicable facilities. Suggested modification for R9: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that exceeds the Facility Rating or Stability criteria upon which the SOL is based.
Yes
There is no reliability purpose served by an Entity developing and posting specifications of data needed to perform its Operational Planning Analysis and Real-time monitoring. The only reliability action that matters is the request for data specific to other Entities in order to perform analysis and monitor operating conditions. These requirements would be more effective if they targeted the following principles: 1. Identify the data needed to perform analysis and effectively monitor operating conditions, 2. Identify the Entities that may have data useful to support analysis and monitoring operating conditions and, 3. Seek to obtain the data from other Entities by engaging the other Entities and coming to a mutual agreement regarding data exchange with the Entity Requirement R5 does not allow for "mutual agreement" as the SDT has suggested in their response to comments from the last draft. As written, this requirement will cause an Entity that is a recipient of a request for data to fail the requirement if a mutual agreement cannot be made. The SDT further states in their response to comments that requirements R1 and R2 ensure disparity between Entities cannot occur. On the contrary, the specifications that are developed as required by these requirements lock an Entity into that specification. If another Entity cannot meet any part of the specification in a data exchange request, there is no recourse in these requirements to relax the specification. The SDT has good intentions, however, these requirements as written do not allow for the flexibility needed in the exchange of data with other parties.
No other comments.
No
In addition, the VSL for R5 in TOP-003 does not reflect partial efforts to exchange data by Entities.
No other comments.

Please see additional comments received from AEP and ACES Power Marketing.

Attached

Comment Form for 7th Draft of Standards

Project 2007-03 Real-time Operations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the 7th draft and successive ballot of the standards for Real-time Operations (Project 2007-03) must be submitted by **April 20, 2012**. If you have questions please contact Ed Dobrowolski at ed.dobrowolski@nerc.net or by telephone at (609) 947-3673.

Background Information:

This posting represents a successive ballot for TOP-001-2, TOP-002-3, and TOP-003-2.

In the 7th posting for Project 2007-03, the Real-time Operations Standard Drafting Team (RTOSDT) has attempted to clarify the proposed changes to the TOP family of standards based on industry comments received for the 6th posting and suggestions made during the Quality Review. Changes made were:

TOP-001-2:

- Requirement R1 – Allowed for plural Transmission Operators and deleted second instance of 'identified'
- Requirement R6 – changed 'the' to 'its' Reliability Coordinator
- Requirement R8 – changed 'internal area ' to 'internal to its Transmission Operator Area'; changed the Time Horizon to only Operations Planning
- Requirement R10 – changed 'each' SOL to 'an' SOL
- Data Retention – Changed voice recordings to 90 calendar days from three calendar months
- Revised VSLs for Requirements R1, R3, R5, and R10

TOP-002-3:

- Requirement R2 - changed 'internal area ' to 'internal to its Transmission Operator Area'

TOP-003-1:

- Applicability – added Distribution Provider
- Requirement R2 – added analysis functions for the Balancing Authority
- Requirement R3 – Cited the tie to Requirement R1 and made the language in Requirement R3 consistent with that in Requirement R1
- Requirement R4 - Cited the tie to Requirement R2 and made the language in Requirement R4 consistent with that in Requirement R2
- Requirement R5 – added Distribution Provider
- Measures M3 and M4 – clarified the web posting item of evidence

- Revised VSLs for Requirements R1, R2, R3,and R4

The Implementation Plan and effective dates for all three standards now show a twelve month compliance period for all requirements except Requirements R1, R2, R3, and R4 of TOP-003-2 which will become effective ten months from the approval date.

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments:

In the previous comment period, AEP requested clarification on whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumed this was based on Real Time Flow, but we encouraged the drafting team to provide clarifying language to make it more clear to the reader. The drafting team responded by noting that IROLs have been defined as both pre-contingent and post-contingent, and that the exact definition of the IROL must be honored. However, no such clarifying language was added to the standard. Time and time again, industry has provided comments to standard drafting teams in an effort to help avoid CANs, Interpretation Requests, and to increase the consistency of interpretation by both CEA's and industry. In this case, while the team provided insight in their comments, the resulting lack of changes to the standard still leave unnecessary ambiguity that could be easily addressed. Ambiguity of any kind deters from, rather than promotes, the reliability of the BES. Until such clarification is added to the standard itself, AEP cannot support the drafting team's efforts in revising TOP-001-2.

R1: The timeframe should be identified.

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments:

In the previous comment period, AEP requested clarification on whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumed this was based on Real Time Flow, but we encouraged the drafting team to provide clarifying language to make it more clear to the reader. The drafting team responded by noting that "TOP-002-3 is about Operations Planning, thus it cannot be addressing actual Real-time flow" and "It addresses those flows contained in the Operational Planning Analysis (OPA) and the assessment thereof." However, no such clarifying language was added to the standard. As stated in our response to Question #1, industry has provided comments to standard drafting teams in an effort to help avoid CANs, Interpretation Requests, and to increase the consistency of interpretation by both CEA's and industry. And once again, while the team provided insight in their comments, the resulting lack of changes to the standard still leave unnecessary ambiguity that could be easily addressed. Ambiguity of any kind deters from, rather than promotes, the reliability of the BES. Until such clarification is added to the standard itself, AEP cannot support the drafting team's efforts in revising TOP-002-3.

Rather than using terms such as "real-time flow", we recommend using "projected post-contingency" and "projected pre-contingency".

3. The SDT made changes to TOP-003-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments:

In the previous comment period, AEP suggested that R5 be modified so that it does not unintentionally create an edict to provide "any data" to parties simply because R5 could be interpreted as allowing requests of any kind. The SDT responded by stating that "Requirement R5 is bound by the constraints of Requirements R1 and R2 so that not just any information can be requested." AEP does not see any explicit constraints specified in R1 or R2, and even if constraints were noted there, see nothing that would indicate those constraints would also apply to R5. At the most, the only possible constraint could be the "mutually agreeable format", however that would seem to provide no bounds or constraints on the kind or amount of data being requested. We suggest providing further clarification that what has been mutually agreed to by the parties involved, goes beyond simply the format of the data. In addition, it needs to be made clear that those constraints also apply to R5. Until such clarification is added to the standard itself, AEP cannot support the drafting team's efforts in revising TOP-003-2.

4. The SDT is suggesting the retirement of three requirements in PRC-001 since those requirements deal with data handling and can now be incorporated in the data specification concept suggested for TOP-003-2. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☒ Yes

   ☐ No

   Comments: While AEP supports, in general, the removal of redundant requirements across standards, we do not yet agree with the proposed changes to TOP-003-2 (for the reasons provided in our response to Question #3). As such, AEP will reserve comment on any future changes that might be made to PRC-001 until further progress is made on TOP-003-2.

5. The VRF, VSL, and Time Horizons are part of a non-binding poll. Please indicate whether you agree or disagree with the VRF, VSL, and Time Horizon assignments. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments:

   In general, the VRFs and VSLs are too severe and punitive. Those stated for R1, R2, and R5 of TOP-001-2 are especially so, given what we see as open-endedness to what might be requested. As a result, AEP cannot support the proposed VRFs and VSLs.

6. If you have any other comments on these standards that you have not already provided in response to the prior questions, please provide them here.

   Comments:

Comment Form for 7th Draft of Standards

Project 2007-03 Real-time Operations

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You do not have to answer all questions. Enter All Comments in Simple Text Format.

Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

1. The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments: We generally agree with TOP-001 and the changes since the last posting. However, we continue to believe that use of the language "know or expected to be" in Requirement R3 is confusing and that this is a case where brevity is more effective in communicating the requirement. We believe striking this clause will improve the clarity of the requirement. As the clause is written now, it is not clear to whom it applies? We assume the SDT intended for the notification to be based on the expectation or knowledge of the TOP to whom the requirement applies. However, the clause is not clear on this but is rather a statement that appears to be some general knowledge or expectation. This opens the possibility of an auditor substituting their expectation or knowledge over the applicable TOP. Requirement R5 has a similar issue.

   We are concerned that the examples listed in Requirement R5 may be too simplistic and could be interpreted too literally. A change in load is one example. Thus, a simple reading of the requirement would imply that a Transmission Operator that has a 1 MW change in a 10,000 MW would be required to notify the Reliability Coordinator. Clearly, that is not what is intended. To resolve this issue, two solutions could be applied. One solution would be to state that changes must be significant. A second solution would be to strike the examples altogether.

   Requirements R10 and R11 are inconsistent. Requirement R10 states the Transmission Operator must inform the RC of "its actions" to mitigate an IROL or SOL that has been exceeded while Requirement R11 compels the Transmission Operator "to act or direct others to act" to mitigate an IROL or SOL that has been exceeded. While we consider that a Transmission Operator directing others to act is the same as taking action itself, it would appear Requirement R11 does not consider directed actions as the actions of the Transmission Operator. This would imply that Requirement R10 does not include communication of the directed actions since it applies to Transmission Operator actions. However, we do not believe exclusion of Transmission Operator actions was intended in Requirement R10. The simplest solution to align these two requirements more closely would be to change "its" in Requirement R10 to "the". In this way, Requirement R10 is not limited to only the actions taken directly by the Transmission Operator.

   The language in the Data Retention section regarding Requirements R7 and R9 needs to be made more consistent with the requirement. We are concerned that language could be interpreted as compelling the Transmission Operator to retain data for any IROL that is temporarily exceeded for a duration less than T_v or an SOL that is exceeded for a time that does not violate the criteria upon which it is based. Neither of these instances would represent a violation of either Requirement R7 or R9. Thus, the data is not necessary to be retained.

Under the Compliance Enforcement Authority section, we suggest “entities” in the first bullet and “functional entities” in the second bullet should be changed to “registered entities”. This will make them consistent with one another and the function model. The “Reliability Functional Model Technical Document” describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.

2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments: We generally agree with the changes to the standard. However, we have identified the following concerns.

   TOP-001-2 R8 implies the Transmission Operator must look for SOLs that are not IROLs in its Operational Planning Analysis that must be completed per TOP-002-3 R1. There is no such requirement in TOP-002-3 R1 or any other requirement that compels a Transmission Operator to look for these SOLs that are not IROLs. Thus, the SDT needs to clarify if a Transmission Operator is required to look for these SOLs that are not IROLs in the Operational Planning Analyses and why they are not referenced in TOP-003-2 R1. If the SDT did not intend for a Transmission Operator to be required to look for these SOLs that are not IROLs, then it needs to refine TOP-001-2 R8 to be clear that the Transmission Operator may not have a need for these SOLs that are not IROLs. TOP-002-3 R2 further confuses the situation by referring to the SOLs that are not IROLs that are identified in TOP-002-3 R1 rather than TOP-001-2 R8.

   Under the Compliance Enforcement Authority section, we suggest “entities” in the first bullet and “functional entities” in the second bullet should be changed to “registered entities”. This will make them consistent with one another and the function model. The “Reliability Functional Model Technical Document” describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.

We disagree with the inclusion of voice recordings as an example of the type of evidence that might be retained for TOP-002-3. Operational Planning Analyses are typically conducted in a back office where communications would not be recorded. This might create the impression that there is now a requirement to record such conversations. Recording of these conversations could mute much of the discussion that occurs among personnel performing these studies and working to resolve issues identified in them. Also, the three months retention period is not consistent with the change made to the retention period in TOP-001-2. It was changed to 90 days for voice recordings.

3. The SDT made changes to TOP-003-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☒ Yes

   ☐ No

   Comments: Generally, we agree with the standard. However, we have one concern regarding the Data Retention section. The third bullet compels the Transmission Operator to retain evidence for three calendar years that it distributed its data specification. Because the data needs do not change frequently, it is possible that the Transmission Operator will have periods greater than three years in which the data specification was not updated and, thus, not communicated. What data and information would the Transmission Operator use to demonstrate compliance in this situation? Would an attestation be appropriate? If so, the measure should be updated to reflect this.

   All of the responses to comments regarding concerns of Requirement R5 indicate that the SDT intended for Requirement R5 to apply to the general satisfaction of the data specification and not any specific data points. However, the Data Retention section does not support this view point. It requires retention of 90 days worth of data. Normally, short periods of data are retained when they are expected to be voluminous. Thus, we assume the Data Retention section was anticipating that the actual data supplied would be retained. This seems inconsistent with the concept of generally satisfying the data specification. It would make more sense to have a statement from the

Transmission Operator indicating the data specification has been satisfied or documentation of the enabling of data links to demonstrate general satisfaction of the data requirements.

Under the Compliance Enforcement Authority section, we suggest “entities” in the first bullet and “functional entities” in the second bullet should be changed to “registered entities”. This will make them consistent with one another and the function model. The “Reliability Functional Model Technical Document” describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.

4. The SDT is suggesting the retirement of three requirements in PRC-001 since those requirements deal with data handling and can now be incorporated in the data specification concept suggested for TOP-003-2. Do you agree with the changes the drafting team has made?

   If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments: While we are supportive of the changes, they do not appear to be coordinated with the Project 2007-06 System Protection Coordination that was started recently. It appears to retain the retired requirements.

5. The VRF, VSL, and Time Horizons are part of a non-binding poll. Please indicate whether you agree or disagree with the VRF, VSL, and Time Horizon assignments. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

   ☐ Yes

   ☒ No

   Comments: The Moderate and High VSLs for TOP-001-2 R3, R5, R6, and R8 incorrectly use an “or” condition when “and” is necessary to establish the range of percentages of performance. As written now, any percentage from 0 to 100% qualifies for both VSLs.

   The following boiler plate language that is written before the VSLs for TOP-001-2 R8 needs to be included before all sets of VSLS that give an option to use integers or percentages. Otherwise, the VSLs will overlap. It should be included before TOP-001-2 R3, R5, and R6.

"For the Requirement X VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation."

For the Severe VSL of TOP-002-3 R3, an extra space is needed before "15%".

6. If you have any other comments on these standards that you have not already provided in response to the prior questions, please provide them here.

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Real-time Transmission Operations – Project 2007-03

The Real-time Transmission Operations Drafting Team thanks all commenters who submitted comments on the 7th draft and successive ballot of the standards for Real-time Operations (Project 2007-03). These standards were posted for a 30-day public comment period from March 22, 2012 through April 20, 2012. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 41 sets of comments, including comments from approximately 143 different people from approximately 111 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

The SDT made several clarifying changes to the project standards as a result of industry comments:

- TOP-001-2: deleted Operations Planning from the Time Horizons for Requirement R1
- TOP-002-3: changed to ninety calendar days in Data Retention
- TOP-003-2: added a reference to analysis functions to Requirement R2, Part 2.1 for consistency with the main requirement
- VSLs for TOP-001-2: added clarifying language to Requirements R3, R5, and R6 for consistency with Requirement R8

The changes made are clarifying in nature and do not change the content or intent of the requirements. Therefore, the SDT is requesting that the project be moved to a recirculation ballot.

No new minority opinions arose in this round of comments.

All comments submitted may be reviewed in their original format on the standard's project page:

http://www.nerc.com/filez/standards/Real-time_Operations_Project_2007-03.html

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual:
http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_Rev%201_20110825.pdf.

NERC

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	David Kiguel	Hydro One Networks Inc.	NPCC	1
9.	Michael Lombardi	Northeast Utilities	NPCC	1
10.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Bruce Metruck	New York Power Authority	NPCC	6
12.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
13.	Robert Pellegrini	The United Illuminating Company	NPCC	1
14.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
15.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
16.	Brian Robinson	Utility Services	NPCC	8
17.	Saurabh Saksena	National Grid	NPCC	1
18.	Michael Schiavone	National Grid	NPCC	1
19.	Wayne Sipperly	New York Power Authority	NPCC	5
20.	Tina Teng	Independent Electricity System Operator	NPCC	2
21.	Donald Weaver	New Brunswick System Operator	NPCC	2
22.	Ben Wu	Orange and Rockland Utilities	NPCC	1
23.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Ron Sporseen	PNGC Group Comments	X		X	X				X		

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe Jarvis	Blachly-Lane Electric Cooperative	WECC	3
2.	Dave Markham	Central Electric Cooperative	WECC	3
3.	Dave Hagen	Clearwater Power Company	WECC	3
4.	Roman Gillen	Consumers Power Inc.	WECC	1, 3
5.	Roger Meader	Coos-Curry Electric Cooperative	WECC	3
6.	Dave Sabala	Douglas Electric Cooperative	WECC	3
7.	Bryan Case	Fall River Electric Cooperative	WECC	3
8.	Ray Ellis	Lincoln Electric Cooperative	WECC	3
9.	Annie Terracciano	Norther Lights Inc.	WECC	3
10.	Aleka Scott	PNGC	WECC	4
11.	Heber Carpenter	Raft River Rural Electric Cooperative	WECC	3
12.	Steve Eldrige	Umatilla Electric Cooperative	WECC	1, 3
13.	Marc Farmer	West Oregon Electric Cooperative	WECC	4
14.	Margaret Ryan	PNGC	WECC	8

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Emily Pennel	Southwest Power Pool Regional Entity										X

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Jake Burger	Nebraska Public Power District	MRO	1, 3, 5
3.	Doug Callison	Grand River Dam Authority	SPP	1, 3, 5
4.	Gary Cox	Southwestern Power Adminstration	SPP	1, 5
5.	David Dieterich	Omaha Public Power District	MRO	1, 3, 5
6.	Kim Donghyeon	Burns & McDonald	NA - Not Applicable	NA
7.	Allan George	Sunflower Electric Power Corporation	SPP	1
8.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
9.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
10.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
11.	Paul Lampe	City of Independence, Power & LIght Department	SPP	3
12.	Julie Lux	Westar Energy	SPP	1, 3, 5, 6
13.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
14.	Kyle McMenamin	Xcel Energy	SPP	1, 3, 5, 6
15.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
16.	Terry Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
17.	Randy Root	Grand River Dam Authority	SPP	1, 3, 5
18.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
19.	Sean Simpson	Board of Public Utilities, City of McPherson	SPP	1, 3, 5
20.	Angela Summer	Southwestern Power Administration	SPP	1, 5
21.	Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6

4.	Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alfonso Juarez III	IID	WECC	1, 3, 4, 5, 6
2.	Joel Fugett	IID	WECC	1, 3, 4, 5, 6

5.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		RFC	5
2.	Mike Garton		MRO	5
3.	Michael Crowley		SERC	1, 3, 5, 6

6.	Group	WILL SMITH	MRO NSRF	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL/NSP	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	3, 4, 5, 1
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 4
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	THERESA ALLARD	MPC	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Laney	Luminant Generation Company LLC	ERCOT	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Jake Burger	Nebraska Public Power District	MRO	1, 3, 5
3.	Doug Callison	Grand River Dam Authority	SPP	1, 3, 5
4.	Gary Cox	Southwestern Power Adminstration	SPP	1, 5
5.	David Dieterich	Omaha Public Power District	MRO	1, 3, 5
6.	Kim Donghyeon	Burns & McDonald	NA - Not Applicable	NA
7.	Allan George	Sunflower Electric Power Corporation	SPP	1
8.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

9.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
10.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
11.	Paul Lampe	City of Independence, Power & LIght Department	SPP	3
12.	Julie Lux	Westar Energy	SPP	1, 3, 5, 6
13.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
14.	Kyle McMenamin	Xcel Energy	SPP	1, 3, 5, 6
15.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5
16.	Terry Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
17.	Randy Root	Grand River Dam Authority	SPP	1, 3, 5
18.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
19.	Sean Simpson	Board of Public Utilities, City of McPherson	SPP	1, 3, 5
20.	Angela Summer	Southwestern Power Administration	SPP	1, 5
21.	Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Steve Rueckert	Western Eledtricity Coordinating Council										X

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted	Snodgrass	WECC	1
2.	Tim	Loepker	WECC	1
3.	John	Anasis	WECC	1
4.	Deanna	Phillips	WECC	1, 3, 5, 6
5.	Rebecca	Berdahl	WECC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

6. Erika	Doot	WECC	3, 5, 6
7. Kristy	Humphrey	WECC	1
8. Don	Watkins	WECC	1
9. Fran	Halpin	WECC	5

				1	2	3	4	5	6	7	8	9	10
12.	Group	Michael Gammon	Kansas City Power & Light	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jessi Tucker	Kansas City Power & Light	SPP	1, 3, 5, 6
2. Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6
3. Harold Wyble	Kansas City Power & Light	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
13.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
14.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
15.	Individual	Antonio Grayson`	Southern Company	X		X		X	X				
16.	Individual	Molly Devine	Idaho Power Company	X									
17.	Individual	Joe Couturier	SSOE Group										
18.	Individual	Michael Falvo	Independent Electricity System Operator		X								
19.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
20.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
21.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
22.	Individual	Rich Salgo	NV Energy	X		X		X					
23.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
24.	Individual	Andrew Z. Pusztai	American transmission Company	X									
25.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
26.	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
27.	Individual	Larry Raczkowski	FirstEnergy Corp	X		X	X	X	X				
28.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
29.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
30.	Individual	Darryl Curtis	Oncor Electric Delivery	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
31.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
32.	Individual	Randall McCamish	City of Vero	X		X							
33.	Individual	J. S. Stonecipher, PE	Beaches Energy Services of theCity of Jacksonville Beach, Florida	X								X	
34.	Individual	Gregory Campoli	New York Independent System Operator		X								
35.	Individual	Patrick Brown	Essential Power, LLC					X					
36.	Individual	Tony Jankowski	Wisconsin Electric Power Company			X	X	X					
37.	Individual	Kathleen Goodman	ISO New England Inc	X	X	X		X	X				
38.	Individual	Brian J Murphy	NextEra Energy, Inc.	X		X		X	X				
39.	Individual	Russell A. Noble	Cowlitz County PUD			X	X	X					
40.	Individual	Thomas E. Foltz	AEP										
41.	Individual	Jason Marshall	ACES Power Marketing										

1. **The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The majority of the comments received requested clarification or explanation of why the SDT did what it did. Only one change, to the Time Horizon for Requirement R1, was made due to comments.

Several commenters remarked that there was a potential problem with relying on a definition being developed in another project that wasn't approved as yet. As has been explained previously, the SDT is working closely with the Reliability Coordination Standard Drafting Team (RC SDT) that is responsible for defining the term 'Reliability Directive'. The use of that term within this standard is somewhat generic in nature. The SDT believes that the progress in developing the definition is sufficient to warrant continued progress of Project 2007-03 without significant concerns of wasted effort or time. And, as shown in the Implementation Plan, the two projects will be filed at FERC together in one package.

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-day Operations, Real-Time Operations]

Organization	Yes or No	Question 1 Comment
Kansas City Power & Light Co.	Negative	Comments and concerns with the proposed standards have been expressed within the NERC comment form
American Electric Power	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Florida Municipal Power Agency	Negative	Please see FMPA comments submitted separately.
Xcel Energy, Inc.	Negative	Please refer to Xcel Energy's filed comments related to this project.

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Negative	Please see comments submitted by Joe Petaski (Manitoba Hydro)
Bonneville Power Administration	Negative	See BPA's submitted comments
Wisconsin Electric Power Co.	Negative	See WE group comments
Xcel Energy, Inc.	Negative	Xcel Energy submitted comments in Standard Comment Form.
FirstEnergy Energy Delivery, FirstEnergy Solutions	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.
Ohio Edison Company	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.
Response: Thank you for submitting comments. Responses to your comments are addressed below.		
ReliabilityFirst Corporation	Abstain	ReliabilityFirst abstains and offers the same comments as submitted via the previous comment posting period.
Response: The SDT points RFC to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
Brazos Electric Power Cooperative, Inc.	Negative	Additional clarification is necessary that warrants our negative vote. See the issues raised in the comments by ACES Power Marketing.
ACES Power Marketing	No	We generally agree with TOP-001 and the changes since the last posting. However, we continue to believe that use of the language “know or expected to be” in Requirement R3 is confusing and that this is a case where brevity is more effective in communicating the requirement. We believe striking this clause will improve the clarity of the requirement. As

Organization	Yes or No	Question 1 Comment
		the clause is written now, it is not clear to whom it applies? We assume the SDT intended for the notification to be based on the expectation or knowledge of the TOP to whom the requirement applies. However, the clause is not clear on this but is rather a statement that appears to be some general knowledge or expectation. This opens the possibility of an auditor substituting their expectation or knowledge over the applicable TOP. Requirement R5 has a similar issue. We are concerned that the examples listed in Requirement R5 may be too simplistic and could be interpreted too literally. A change in load is one example. Thus, a simple reading of the requirement would imply that a Transmission Operator that has a 1 MW change in a 10,000 MW would be required to notify the Reliability Coordinator. Clearly, that is not what is intended. To resolve this issue, two solutions could be applied. One solution would be to state that changes must be significant. A second solution would be to strike the examples altogether. Requirements R10 and R11 are inconsistent. Requirement R10 states the Transmission Operator must inform the RC of "its actions" to mitigate an IROL or SOL that has been exceeded while Requirement R11 compels the Transmission Operator "to act or direct others to act" to mitigate an IROL or SOL that has been exceeded. While we consider that a Transmission Operator directing others to act is the same as taking action itself, it would appear Requirement R11 does not consider directed actions as the actions of the Transmission Operator. This would imply that Requirement R10 does not include communication of the directed actions since it applies to Transmission Operator actions. However, we do not believe exclusion of Transmission Operator actions was intended in Requirement R10. The simplest solution to align these two requirements more closely would be to

Organization	Yes or No	Question 1 Comment
		change "its" in Requirement R10 to "the". In this way, Requirement R10 is not limited to only the actions taken directly by the Transmission Operator. The language in the Data Retention section regarding Requirements R7 and R9 needs to be made more consistent with the requirement. We are concerned that language could be interpreted as compelling the Transmission Operator to retain data for any IROL that is temporarily exceeded for a duration less than T_v or an SOL that is exceeded for a time that does not violate the criteria upon which it is based. Neither of these instances would represent a violation of either Requirement R7 or R9. Thus, the data is not necessary to be retained. Under the Compliance Enforcement Authority section, we suggest "entities" in the first bullet and "functional entities" in the second bullet should be changed to "registered entities". This will make them consistent with one another and the function model. The "Reliability Functional Model Technical Document" describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.

Response: R3 & R5: The SDT disagrees. By utilizing the results of the required Operational Planning Analysis, the Transmission Operator will know what other entities are known or expected to be affected. Striking the clause will not provide clarity but open up other questions. No change made.

R5: The use of the term 'significant' would not provide any additional clarity as it is still a subjective term open to interpretation. Merely striking the examples does not provide additional clarity either as it leaves the situation completely open to interpretation. The SDT believes that including the examples provides sufficient clarity. Any auditor trying to use a 1 MW change on a 10,000 MW system will be hard-pressed to justify their actions. No change made.

R10: The SDT disagrees. If the commenter accepts that directing others to act is the same as taking action itself, then the SDT

Organization	Yes or No	Question 1 Comment
asserts that Requirement R10 is aligned with Requirement R11. No change made. Data retention: The SDT believes that by incorporating a reference to the requirements in question within the data retention language that the concern expressed by the commenter is not an issue. No change made. CEA: The SDT is using language here that has been utilized in multiple standards projects to date and was supplied by staff as accepted language. Furthermore, the SDT does not agree that the suggested changes will provided any additional clarity. No change made.		
Lakeland Electric	Negative	Please refer to comments submitted by FMPA.
Florida Municipal Power Pool	Affirmative	See FMPA Comments
Florida Municipal Power Agency; City of Vero; Beaches Energy Services of the City of Jacksonville Beach, FL	No	The existing TOP-001-1 R7 essentially requires communication to the RC and neighboring TOPs any time a Facility is to be switched. The new TOP-001-2 R5 will only require such communication when such switching would result in an "Adverse Reliability Impact" defined as: "The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection." This significantly reduces the requirements for communication / notification for switching Facilities. It is worthwhile to communicate switching of some Facilities whether or not they would result in an "Adverse Reliability Impact". Suggest rephrasing to something like any unplanned switching of Facilities not "noticed" through data provision of TOP-003-2. With the number of human error events that have occurred, we should not be reducing the communication / notification requirements. R8 is not needed since it is already covered in FAC-014-2 R5.2. As a result, R9, R10 and R11 ought to be modified to refer to FAC-014-2 rather than R8.
Response: R7: The SDT believes that notification for any switching event is contrary to good operating practice as it would load up the message queue with unnecessary information and could lead to an operator missing an important message within a large		

Organization	Yes or No	Question 1 Comment
group of unneeded messages. TOP-003-2 allows for an entity to request reliability-based information from another entity so they may include status on any piece of equipment that may possibly effect its operations. Therefore, the SDT does not agree that a reliability gap has been created. No change made. R8: The SDT notes that there are subtle differences in TOP-001-2 and FAC-014-2. FAC-014-2 provides a simple list of SOLs while TOP-001-2 is looking at particular SOLs that need special treatment. Therefore, there is no redundancy. No change made.		
Xcel Energy, Inc.	Negative	Drafting Team didn't address the Regional differences on the treatment of SOLs. R8 – Please clarify the difference between R8 of TOP-001-2, and R2 & R5 of FAC-014-2. We would expect in some regions, depending on the RC's SOL methodology, that this would be the same information. For example, in SPP, all Facility Ratings are considered SOLs. Compliance with R9 of TOP-001-2 will prove quite difficult in regions like this. Please clarify what the drafting team envisions being the difference between these two standards, and what is expected to be given to the RC under each. R9 - We appreciate the drafting team's efforts. However, we are still concerned that R9 will not allow the Transmission Operator the flexibility to identify the best SOL recovery approach, without incurring a violation of the requirement. Instead, the TOP may be forced to shed load in order to avoid violating the requirement. This is not ideal, especially when the situation could be mitigated successfully with alternative measures. It is not clear if an entity is allowed to use an RC-approved contingency plan to mitigate a situation that would cause a Facility Rating violation (i.e. the Facility Rating is the SOL), without also incurring a violation of R9. To further explain, if an entity foresees exceeding an SOL in its OPA, and obtains approval from the RC on their proposed contingency plan (which includes a Facility Rating violation), will that entity be considered in violation of R9 once the exceedance occurs and the contingency plan is implemented?
Response: The SDT does not agree that it is necessary to spell out any regional differences in the treatment of SOLs. The		

Organization	Yes or No	Question 1 Comment
requirements are generic in that respect as they should be. No change made. R8: The SDT believes that there are subtle differences in TOP-001-2 and FAC-014-2 that the commenter is missing. FAC-014-2 provides a simple list of SOLs while TOP-001-2 is looking at particular SOLs that need special treatment. Therefore, there is no redundancy. No change made. R9: There is nothing in this standard that ties the Transmission Operator to any particular plan or action so the SDT believes that the commenter's fears are ungrounded. No change made.		
National Association of Regulatory Utility Commissioners	Negative	Given the term Reliability Directive is being used as a defined term but does not yet exist as a defined term in the NERC Glossary and is not proposed to be a defined term in the Glossary with this proposal, it is premature to approve this revised standard.
Hydro One Networks, Inc.	Negative	The standard uses the term "Reliability Directive" which is currently and formally under development as part of another project. The posting states that this definition was agreed to by all affected project teams using it. However if the other project team formally charged with this definition's development, changes it, then this standard and perhaps others, will have to be revisited.
Utility Services, Inc.	Negative	There is use of the term "Reliability Directive" in the standard which is currently and formally under development as part of another project. The posting states that this definition was agreed to by all affected project teams using it, however if the other project team formally charged with this definition's development, changes it, then this standard and perhaps others, will have to be revisited. Bringing these standards forward seems inefficient and problematic.
Response: The SDT appreciates your concerns, but has always intended to deal with the coordination issue involved here in a decisive manner. As has been explained previously, the SDT is working closely with the RC SDT that is responsible for defining the term 'Reliability Directive'. The use of that term within this standard is somewhat generic in nature. The SDT believes that the		

Organization	Yes or No	Question 1 Comment
progress in developing the definition is sufficient to warrant continued progress of Project 2007-03 without significant concerns of wasted effort or time. The RTO SDT (Project 2007-03) and the RC SDT's project (Project 2006-06) will be filed together at FERC. No change made.		
Santee Cooper	Negative	In R8, SOLs are identified according to each entity's SOL methodology. This requirement seems to assume a certain methodology for identifying SOLs. Local area issues such as the examples cited in the rationale may not be of consequence to the BES and not considered an SOL. Also, over-communication of local area issues to the RC will inundate them and could become a detriment to the reliability of the BES. We believe that entities should be allowed to report SOLs according to their required methodology they have established. What was the rationale of reducing the implementation time from twenty-four months to twelve months?
Response: R8: SOLs are developed through a required methodology in FAC-014-2. Nothing in TOP-001-2 changes that fact. Requirement R8 is intended solely for those SOLs, that while not IROLs, are more important to the Transmission Operator Area than a typical SOL would be. No change made. IP: The effective date was changed following numerous comments to the sixth posting that asserted the implementation plan would take excessive time and needed to be shortened. It was also based on the fact that the proposed requirements represent what is already being done in the field in many areas.		
INTELLIBIND	Negative	Inclusion of "examples" is not appropriat and leads to a compliance conflict on whether these examples must be addressed or not. R8, 9 and 11 place unneeded additional burden on entities to prove they are properly complying.
Response: The SDT believes that the language of the requirement (and examples) is such that that the commenter's fears are unwarranted and will not lead to conflict. No change made.		

Organization	Yes or No	Question 1 Comment
The commenter has not supplied any information on the details of why there is an unneeded burden. Therefore, the SDT is unable to reply. Proof of compliance with a requirement is part of a mandatory compliance mechanism. In recognition of this compliance burden, the requirements mentioned were carefully crafted with the end in view that a registered entity should be able to affirmatively prove compliance. No change made.		
MidAmerican Energy Co.	Negative	NERC standards cannot be vague and undefined or NERC interprets the standard and creates new requirements through the Compliance Application Notice process. The rational specified for R8 shows that R8 deals with a Transmission Operator defined special subset of SOLs. However, the current wording in R8 does not use the wording "special subset of SOLs as defined by the TOP". The standard uses "as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis". This is not clear enough for a black and white compliance audit and therefore is inadequate. Further in R9 continous duration remains undefined. Therefore, specific wording needs to be added to show that R9 applies to the "special subset of SOLs with there corresponding continous duration timeframes as defined by the TOP". Last, the the same wording and definition must be applied to FAC-011-2 R2 to remain consistent and clear.
Response: The rationale is simply an explanation of Requirement R8 and is intended to ensure that the responsible entity and auditor understand the requirement – it is the language in the requirement, not the language in the text box, that is enforceable. Therefore, there is no inconsistency in the wording. No change made. Continuous duration is a common term and the Webster's dictionary meanings can and should be applied. The reference in Requirement R9 to Requirement R8 makes it clear as to what is being referenced. No change made. The SDT has reviewed FAC-011-2, Requirement R2 and does not believe that any changes are required in order to maintain consistency as the methodology hasn't been changed. No change made.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>Detroit Edison Company</td><td>Negative</td><td>R3- The sentence should read “… inform its Reliability Coordinator and other Transmission Operator(s), …” The word other is missing in the current draft.

R6- The statement “… negatively impacted interconnected NERC registered entities…” is to vague. This could be an easy trip up during an audit.

M6- same as R6- The statement “… negatively impacted interconnected NERC registered entities…” is to vague.

VSLs- R6- The statement “… negatively impacted interconnected NERC registered entities…” is to vague.</td></tr>
<tr><td colspan="3">Response: R3: The SDT asserts that ‘other’ is understood and no additional clarity would be provided by adding it. No change made.

R6, M6, & VSL: The SDT believes that a ‘negatively impacted’ entity is clear and not vague. No change made.</td></tr>
<tr><td>Westar Energy</td><td>Negative</td><td>SDT has not adequately addressed previous comments.</td></tr>
<tr><td colspan="3">Response: Without specifics, the SDT is unable to respond.</td></tr>
<tr><td>Wisconsin Electric Power Marketing; Wisconsi Energy Corp.</td><td>Negative</td><td>The SDT’s response for previous comments on R6 is that “The intent of the requirement is to notify those entities that are directly affected by the telemetry outage. “ If that is the intent of the requirement then the requirement should state that.

Also, “negatively impacted” needs to have some sort of bounds. Loss of $1 in revenue is a negative impact.</td></tr>
<tr><td colspan="3">Response: The SDT believes that the intent is clear and that no further explanation is required. No change made.

As the requirement is dealing with telemetry outages, the impact is in loss of data and information as it relates to reliability. Revenue is not within the scope of reliability standards. No change made.</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
Commonwealth of Massachusetts Department of Public Utilities	Negative	There is use of the term "Reliability Directive" in the standard which is currently and formally under development as part of another project. The posting states that this definition was agreed to by all affected project teams using it, however if the other project team formally charged with this definition's development, changes it, then this standard and perhaps others, will have to be revisited. Bringing these standards forward seems inefficient and problematic for many. Also in Requirement 8 there was an issue expressed by one RSC member that System Operating Limits are local limits and should not be subject of part of the NERC standards and the requirement as written creates a "subset" of SOLs that affect reliability. This could create an overly complicated standard and could lead to compliance difficulties.
Response: As has been explained previously, the SDT is working closely with the RC SDT that is responsible for defining the term 'Reliability Directive'. The use of that term within this standard is somewhat generic in nature. The SDT believes that the progress in developing the definition is sufficient to warrant continued progress of Project 2007-03 without significant concerns of wasted effort or time. The RTO SDT (Project 2007-03) and the RC SDT project (Project 2006-06) will be filed together at FERC. No change made. The SDT does not believe that Requirement R8 creates an overly complicated standard or creates compliance difficulties. This requirement was added quite some time ago at the behest of industry as shown in earlier posted comments. There is nothing complicated about it and it is in the control of the Transmission Operator as to how to proceed. No change made.		
Texas Reliability Entity	No	1) Definitions: Texas RE does not agree with the proposed definition of "Reliability Directive" and encourages the SDT to look past a compliance based outlook regarding the word "directive". If there is no Reliability Standard support for use of directives to AVOID emergencies, emergencies will continue to occur. Consider using the broader defined term "Operating Communication" from COM-003 rather than "Reliability Directive" in this standard.

Organization	Yes or No	Question 1 Comment
		2) R1: This requirement, as written, states that the BA, GOP, DP, and LSE must comply with Reliability Directives, which, by definition, are only issued in Emergencies or to prevent instability or Cascading. There is not a requirement in the TOP or IRO standards that obligates a Registered Entity to comply with other directives issued by the TOP or RC used in operating the grid in a reliable manner. For example, some generator operators exceed the operating basepoint that is communicated to the unit by the ISO, which creates congestion and overloads the transmission system. Under the proposed R1 language, there is no requirement for an entity to comply with this type of directive, since it is not a "Reliability Directive" until an Emergency occurs. 3) R3: Requirement R3 seems to be missing some words. It doesn't say WHAT the TOP should inform other entities about. Also, it is not clear if this requirement is supposed to be about planning ("expected to be affected by anticipated Emergencies") or real-time operations ("known to be affected by actual Emergencies") or both. If the latter is intended, the Time Horizon should include Real-Time Operations and Same Day Operations. We suggest changing the language to "Each Transmission Operator shall inform its Reliability Coordinator and other affected Transmission Operator(s) about each actual or anticipated Emergency , which may be determined in Real-time or based on its assessment of its Operational Planning Analysis" 4) R4: Reinsert Generator Operator applicability from old R6. The stated reason for removal of Generator Operator is incorrect and violates the Functional Model which states that a Balancing Authority may direct "resources (Generator Operators and Load-Serving Entities) to take action to ensure balance in real time" and "direct "Generator Operators to implement redispatch for congestion management". Both of those type actions may include rendering emergency assistance. 5) R5: The requirement implies, but does not specifically state a time frame

Organization	Yes or No	Question 1 Comment
		for informing the RC. The RC must be informed in sufficient time in order to respond to the system condition. The phrase "unless conditions do not permit" is ambiguous and should be made more definite. We suggest rewriting R5 as follows: "Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas within a timeframe that is sufficient for the RC and affected Transmission Operators to respond to the system condition, unless communication capabilities have failed." The Time Horizon should also include Operations Planning since the Requirement language includes "known or expected." 6) R6: There is a need to include Generator Operator in this requirement. There is no clarification in the mapping document regarding the loss of the applicability to the Generator Operator (previously in TOP-001-1 R3). 7) R8: This requirement, as written, states that the TOP must inform the RC of SOLs based on its assessment of its Operational Planning Analysis, which, by definition, is an analysis for the next day's operation that may occur either a day ahead or as much as 12 months ahead. SOL violations can occur in Real-Time (e.g., transmission thermal limit violations, voltage violations, etc.) due to forced outages from storms or equipment failures that may not have been studied under the Next-Day analysis and various other real time conditions. We suggest rewording the requirement to read "Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based ON ANTICIPATED OR ACTUAL EMERGENCIES OCCURRING IN REAL-TIME OR BASED on its assessment of its Operational Planning Analysis." It is important to recognize the Real-Time issues because several of the Requirements following Requirement 8 refer to SOLs "identified in Requirement R8." Additionally, since the definition of SOL includes post-

Organization	Yes or No	Question 1 Comment
		contingency criteria, contingencies are not limited to Operational Planning Analysis timeframes. The VSL language also needs to accommodate Real-Time considerations. 8) R9: See our comment regarding R8 - there is a reliability gap because SOLs identified in Real-Time (as opposed to those identified in the Operational Planning Analysis timeframe) are not included. 9) R10: See our comment regarding R8 - there is a reliability gap in the actions needed to return the system to within limits for SOLs identified in Real-Time as opposed to those identified in the Operational Planning Analysis timeframe. 10) R11: See our comment regarding R8 - there is a reliability gap for SOLs identified in Real-Time as opposed to those identified in the Operational Planning Analysis timeframe.11) What is the intended difference between "TOP shall not operate outside any SOL" in R9 and "TOP shall act or direct others to act to mitigate both the magnitude and the duration of exceeding . . . an SOL" in R11? The same action or inaction would likely result in violations of both requirements, resulting in a "double-jeopardy" situation.
Response: 1. The SDT is aware of the work being done with COM-003 as it has maintained close coordination with that SDT. In this case, the SDT believes that the requirements in TOP-001-2 best align with the use of Reliability Directive. Any problems with the proposed definition should be taken up with the RC SDT in Project 2006-06. No change made. 2. The SDT believes that other market protocols, standards and operating protocols and mechanisms are in place today to take care of the type of situations that the commenter has noted. No change made. 3. The SDT does not believe the suggested change adds any clarity. The SDT believes that it is clear as to what needs to be communicated. Since Operational Planning Analysis is generally analyzed at least a day ahead, the SDT, in response to numerous comments in the last posting, changed the Time Horizon to just Operations Planning. No change made. 4. The SDT stands by its reasoning for deletion of the Generator Operator as consistent with the Functional Model v5. No change made.		

Organization	Yes or No	Question 1 Comment
5. The SDT does not believe that the suggested language provides any additional clarity. Requirement R5 is more pertinent to Real-time than Operations Planning which is covered in Requirement R3. No change made. 6. There is no relevance between TOP-001-1, Requirement R3 which concerns reliability directives and this requirement which deals with telemetry outages. If a Generator Operator has telemetry outages it will be noted to the Transmission Operator or Balancing Authority and would be reported as part of their information. No Change made. 7, 8, 9, & 10. The SDT believes that Operational Planning Analysis includes the study of Contingencies and as such will include scenarios that include such conditions as the commenter has pointed out. The SDT reminds the commenter that TOP-002-3 requires the study of all SOLs and that nothing has changed with regard to an entity's responsibilities to operate a reliable system. TOP-001-2 is simply elevating a subset of SOLs to receive special attention. No change made.		
Oncor Electric Delivery	No	Oncor believes that the Reliability Coordinator is in the best position to determine who the negatively impacted interconnected registered entities are and to effectively coordinate communication efforts after receiving the initial planned outage request from the originating entity. In addition, the term "negatively impacted interconnected registered entities" is too broad and too subjective. As a result, we recommend R6 be revised to: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
Response: The SDT believes that the Transmission Operator can, and does, know who will be impacted by outages of telemetry equipment. Placing this responsibility at the Reliability Coordinator level would place an unnecessary burden on those entities and deflect them from their reliability responsibilities. No change made.		
Bonneville Power Administration	No	BPA does not believe that the drafting teams' consideration of our previously submitted comments during the last round was adequate. The response appeared to be based on the assumption that the SOL or IROL was based on a thermal limit, not a stability limit. Since a system can go unstable in less than 1 second, the drafting team's response that, "ratings

Organization	Yes or No	Question 1 Comment
		include the qualifiers of time...” did not make sense to us in the context of a “stability limit”. As stated in BPA’s previous comments, it takes a definite amount of time to readjust the system (change schedules, move generation, or perform other actions) in order to get actual flows down to reliable operating limits when flows have exceeded limits. The standards need to clearly articulate how much time the responsible entities have to accomplish this. The current standard TOP-004-2, R4 clearly articulates a 30 minute rule for this. TOP-001 needs to do the same, especially if TOP-001 will replace TOP-004-2. Previous Comments: Given the potential uncertainty regarding the 30 Minute Rule, BPA suggests adding more clarity to the standard TOP-001-2 as the new draft could be interpreted to mean that one would need to get the flows below the SOL immediately. BPA believes this is not practical because it takes a definite amount of time to change schedules, move generation, or perform other actions in order to reduce loadings on facilities. BPA believes the new draft should include guidance as to how much time the BA or Transmission Operator would be allowed in order to reduce flows when there is an SOL violation. BPA suggests that more clarity be provided and/or the 30 minute rule be added back to the standard. Additional New Comments:TOP-001 introduces a new term and definition, Reliability Directive. This term is used in R1 of the standard in conjunction with two other defined terms, 'Emergency' and 'Adverse Reliability Impacts'. The time horizon described for R1 is ‘Operations-Planning’. The timeframes for which this standard applies are 'Operations-Planning', 'Same-Day Operations' and 'Real-Time'. However, if we review the definitions associated with 'Emergency' and 'Adverse Reliability Impacts', it is clear that these terms are used for events that occur only during real time operations. BPA recommends that R1 be re-worded so that the Time Horizons are consistent with the terms used in the standard; that the Reliability Directive definition be clarified so that the timing of the

Organization	Yes or No	Question 1 Comment
		directive is identified; and that use of the terms 'Emergency' and 'Adverse Reliability Impact' be consistent with their definitions, and the 30 minute rule for getting actual flows back within a reliable limit be inserted. BPA recommends that the applicability of R6 be expanded to also include Generation Operators. The intent of this requirement is for those entities with "telemetering equipment, control equipment and associated communications channels" to coordinate outage of such equipment with its Reliability Coordinator and negatively impacted interconnected NERC registered entities. Though Generation Operators have such equipment, as written, this requirement does not require that the coordinate such outages in the same manner as Balancing Authorities and Transmission Operators are required to under this requirement.

Response: SOLs, by definition, include Stability ratings and those ratings, like all ratings, have a time element associated with them. Therefore, by using ratings and the time elements associated with them, the SDT has provided a definitive timeframe that will provide greater protection to system elements than what was previously stated as 30 minutes may be too long in certain situations. If a stability rating with a T_v of 1 second is the basis for an SOL, then no time in exceedance of the magnitude limit is allowable, and a Transmission Operator facing that issue would have plans in place to avoid exceedance of that limit. No change made.

The SDT is in agreement with the commenter and has deleted Operations Planning from the Time Horizons. From the latest approved version of the Standards Process manual: "Time Horizon: The time period an entity has to mitigate an instance of violating the associated requirement."

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements. [Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-day Operations, Real-Time Operations]

Organization	Yes or No	Question 1 Comment
The SDT asserts that if a timing element is required for a Reliability Directive that the Reliability Directive will include such a timing element. No change made. With the change in the Time Horizons cited above, the terms are now consistent. No further change made. SOLs, by definition, include Stability ratings and those ratings, like all ratings, have a time element associated with them. Therefore, by using ratings and the time elements associated with them, the SDT has provided a definitive timeframe that will provide greater protection to system elements than what was previously stated as 30 minutes may be too long in certain situations. No change made. The SDT stands by its reasoning for deletion of the Generator Operator as consistent with the Functional Model v5. No change made.		
PNGC Group Comments	No	Comments: The PNGC comment group believes there should be a distinction in the “Applicability” section of the standard distinguishing between “Scheduling DP/LSE” and “Non-scheduling DP/LSE”. PNGC members are small rural cooperatives that are “Full service BPA customers.” This means is that BPA is our power supplier and scheduling agent and therefore handles all scheduling, tagging, dispatching of resources and curtailments of load from breakers on BPA’s system for PNGC members. According to a letter from the WECC Reliability Coordinator (VRCC and LRCC) none of PNGC’s members will ever receive a “Reliability Directive”. Such a Directive would be sent to either a Balancing Authority (BA), or a Transmission Operator (TOP). In fact, the Bonneville Power Administration (BPA) is the BA and TOP for many of our members so R1 and R2 are nothing more than a clerical exercise for many DP/LSE entities. We estimate there are over 100 entities that are BPA Full Service customers that are in a similar position and making this standard applicable to them does nothing to enhance reliability. A simple declarative statement in the Applicability section of the standard could focus the intent of the SDT on those entities that need it while lessening the compliance risk and clerical burden for other entities that the standard should not apply to. We suggest:4.

Organization	Yes or No	Question 1 Comment
		Applicability4.1 Balancing Authority4.2 Transmission Operator4.3 Generator Operator4.4 Distribution Provider: With Real-time Operations desk4.5 Load-Serving Entity: With Real-time Operations desk
Response: The SDT believes that the current wording is appropriate for a continent-wide standard. If an entity never receives a Reliability Directive then there is nothing for them to do. No change made.		
Kansas City Power & Light	No	Continuous duration" in R9 is not a defined term and will cause uncertainty and debate under audit as to what time frame this represents. Recommend R9 be modified to reflect the time basis established through the methodology to develop the SOL for the applicable facilities. Suggested modification for R9:Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that exceeds the Facility Rating or Stability criteria upon which the SOL is based.
Response: The SDT sees no additional clarity in the suggested wording change. Continuous duration is a common term and the Webster's dictionary meanings can and should be applied. No change made.		
MRO NSRF	No	For R9, the drafting team did not address "continuous duration". Many entities had commented that the term is vague. Is continuous duration, 8 hours or 15 minutes? For IROL limit violations or Unknown State conditions, the entity has 30 minutes to mitigate the situation.
Great River Energy	Affirmative	Great River Energy agrees with the comments of the MRO NSRF
Response: Continuous duration is a common term and the Webster's dictionary meanings can and should be applied. No change made.		
Idaho Power Company	No	I don't think that this requirement should be retained. With e-tag requirements, mid-hour scheduling and the ability to process an emergency

Organization	Yes or No	Question 1 Comment
		tag at any time it seems like an interchange. What is emergency assistance?
Response: Emergency assistance can mean many things such as a change in dispatch or load shed, etc., that do not result in a energy transaction or e-Tag. e-Tag is not a reliability-based tool and shouldn't be relied on to cover operating situations in Real-time. No change made.		
Consolidated Edison Co. of New York	Affirmative	See NPCC group comments
Northeast Power Coordinating Council	No	It is written in FAC-014-2 R5.2: R5.2. The Transmission Operator shall provide any SOLs it developed to its ReliabilityCoordinator and to the Transmission Service Providers that share its portion of theReliability Coordinator Area.This already mandates that the Transmission Operator provide its Reliability Coordinator SOLs. This requirement and TOP-001 R8 must be made to agree.As explained in the redline version of TOP-001: "Rationale: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations."It is understood that the impacts of some SOLs may attract increased attention because of the operational implications of them being exceeded. It must also be realized that every SOL has a reliability impact. The added wording adds unneeded complication to the Requirement. Will the proposed requirement create a new class of SOLs that might include any that might be "intermittent" in nature, such as those occurring during televised events, etc.? This becomes a moving target, and it may become problematic for keeping track of those SOLs to which these requirements apply, i.e., those that require notification to the Reliability Coordinator, versus those which don't. Regardless, operator responses to any SOL's on their systems should

Organization	Yes or No	Question 1 Comment
		be the same in terms of swiftness and a sense of urgency. The phrase "supporting reliability internal" is used in R8. What constitutes "supporting reliability internal"? This may present compliance issues. Experience has shown that the use of the terms internal, external, local, wide area have presented auditing difficulties that generated documentation issues.
Response: The SDT asserts that there are subtle differences in TOP-001-2 and FAC-014-2. FAC-014-2 provides a simple list of SOLs while TOP-001-2 is looking at particular SOLs that need special treatment. Therefore, there is no conflict. No change made. The commenter is leaving out part of the phrase thus creating a problem in their mind where there is none if everything is taken in context. The whole phrase is "…supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis." When shown in this complete version, the SDT asserts that it is clear as to what is meant and what needs to be done. No change made.		
Manitoba Hydro	No	Manitoba Hydro is voting negative on TOP-001-2 for the following reason:R8 and R9 - In the absence of the rationale box in the final approved version of the standard, R8 is extremely unclear. All SOL's support reliability based on an assessment of operational planning. The requirement (R9) prohibits operation outside any SOL "for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based." However, by NERC definition an SOL is based upon Facility Rating and Stability Criteria, so operating outside the SOL is always going to violate the Facility Rating. The term continuous duration is undefined and as such makes the standard subject to interpretation. It would appear that the standard expects the system operator to do something more than would be done for an IROL.
Response: The SDT fails to see where the absence of a rationale box will make Requirement R8 unclear and the commenter provides no specifics for the SDT to respond to. The SDT believes that Requirement R8 is clear. No change made.		

Organization	Yes or No	Question 1 Comment
The time element for mitigation of the problem is the key to Requirement R9 and the reason for the proposed wording. No change made. Continuous duration is a common term and the Webster's dictionary meanings can and should be applied.		
Consumers Energy	No	The Reliability Directive definition is not strong enough and leaves too much to interpretation. We feel that the other requirements and items in the standard are acceptable and we could support this version if the definition had more clarity.
Response: Reliability Directive is being developed and defined by Project 2006-06 and the term is simply being utilized in this standard. The commenter should provide specific comments to Project 2006-06 during their next posting. No change made.		
AEP	No	In the previous comment period, AEP requested clarification on whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumed this was based on Real Time Flow, but we encouraged the drafting team to provide clarifying language to make it more clear to the reader. The drafting team responded by noting that IROLs have been defined as both pre-contingent and post-contingent, and that the exact definition of the IROL must be honored. However, no such clarifying language was added to the standard. Time and time again, industry has provided comments to standard drafting teams in an effort to help avoid CANs, Interpretation Requests, and to increase the consistency of interpretation by both CEA's and industry. In this case, while the team provided insight in their comments, the resulting lack of changes to the standard still leave unnecessary ambiguity that could be easily addressed. Ambiguity of any kind deters from, rather than promotes, the reliability of the BES. Until such clarification is added to the standard itself, AEP cannot support the drafting team's efforts in revising TOP-001-2. R1: The timeframe should be identified.

Organization	Yes or No	Question 1 Comment
Response: The SDT believes that the definition of IROL speaks for itself and therefore that no further explanation is required within the standard. No change made. The SDT believes that if a timing element is required for a Reliability Directive that the Reliability Directive will include such a timing element. No change made.		
New York Independent System Operator	No	The SDT did not provide reasonable assurance that documented determination of 'Reliability Directive' identification was sufficient to meet R1, in the absents of explicit identificaation during every verbal communication. We believe it is not clear to an auditor that written procedures would be an adequate level of 'identification. A possible solution would be to add R1.1 and spell out that identification of Reliability Directive shall be communicated through approved procedures or verbal identification. In addition, Requirement 11 gives the TOP the authority to "...act or direct others to act..." to mitigate IROL and certain SOL exceedances. Is it the intent of the SDT that the TOP can direct any of the entities to which this standard is applicable? Also SDT should consider a change to say "... act or issue a Reliability Directive to ....' This ties the requirement back to R1 with an obligation to complete the directive. The NYISO is also concern with the use of the definition of 'Reliability Directive' that has not been approved. We recommend balloting TOP-001 simultaneously with the RC Project that includes the definition. As it stands we support the proposed definition.
Response: Communication of Reliability Directives is governed by the COM standards. Comments on same should be directed to Project 2006-06 the next time that project posts for comment. TOP-001-2 uses the term and says nothing about how it is implemented. No change made.		

Organization	Yes or No	Question 1 Comment
It is the intent of the SDT that the Transmission Operator can direct any entity shown in applicability. The SDT sees no additional clarity being provided with the suggested change. No change made. The TOP standards will be filed at FERC jointly with the Project 2006-06.		
SSOE Group	No	TOP-001-2Grammatical: R8 and its supporting rationale refers to a term SOL. The term is 'defined' later in R9. The 'definition' should probably be defined at the time of its first usage. R11 The TO directs someone to do something. However, who is directed is not defined. Is it directed to the RC?
Response: Agree – the SDT moved the definition of the acronym from Requirement R9 to Requirement R8. It is directed to the entity that the Transmission Operator believes can correct or help to correct the problem. Since that entity can't be identified ahead of time in a standard, the SDT believes it is best left as is. No change made.		
Duke Energy	No	While the drafting team has made several improvements to this standard, we believe these additional changes are needed: o The definition of Reliability Directive includes the defined term "Adverse Reliability Impact", which should be replaced by the actual wording of latest (8/4/2011) BOT-approved definition of "Adverse Reliability Impact", since it has NOT yet been approved by FERC. o R3 places the responsibility on a Transmission Operator to possess tools it does not currently utilize. Most companies will study their own area and possibly one or two busses out. In order to be compliant to this standard, it would appear a Transmission Operator would need to possess study tools which are currently utilized by the Reliability Coordinator. Suggest considering adopting language where the Transmission Operator requests assistance in identifying impacts outside their direct interconnects. Suggested rewording: "Each Transmission Operator shall work in

Organization	Yes or No	Question 1 Comment
		conjunction with its respective Reliability Coordinator to inform other Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. [Violation Risk Factor: High] [Time Horizon: Operations Planning,]". o R4, as written, does not consider an entity that might be under the control of an RTO. A Transmission Operator, as a member of an RTO, cannot take actions without the permission unless during an emergency where cascading outages, loss of equipment etc. is involved. If the event described in R4 as currently written is not an immediate emergency, the Transmission Operator would need to gain permission of the RTO to comply. Suggest wording changes to take into consideration entities whose facilities are under RTO control. Suggested rewording: "Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that appropriate agreements are in place, and the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. In the event the Transmission Operator is under the purview of a Regional Transmission Organization (RTO), the Reliability Coordinator of the RTO shall work with its Transmission Operators in requesting available emergency assistance. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]". o R5 - Similar comment to R3. This requirement places the responsibility on a Transmission Operator to possess tools it does not currently utilize. Most companies will study their own area and possibly one or two busses out. In order to be compliant to this standard, it would appear a Transmission Operator would need to possess study tools which are currently utilized by the Reliability Coordinator. Suggest considering adopting language where the Transmission Operator requests assistance in identifying impacts outside their direct interconnects. Suggested rewording: "Each

Organization	Yes or No	Question 1 Comment
		Transmission Operator shall inform its Reliability Coordinator, who shall assist in identifying other Transmission Operators of its operations that are known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations include but are not limited to relay or equipment failures, and changes in generation, Transmission, or Load. [Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]". o R6 - Strike the word "negatively", since no one will be "positively" impacted. o R6 needs to be clarified as to the intent. Does registered entity mean the corporation, or does registered entity mean a TO, BA etc. Suggestion would be to remove NERC registered from the language. o R8 - The SDT has included a Rationale for SOLs that deserve increased attention. Several examples cited in the Rationale are for service to local load, and while the local loads may be important loads, the associated SOLs would have no impact on BES reliability. R8 requires the TOP to inform the RC of such SOLs, and we question why the RC needs to be informed of SOLs that only impact service to local loads. We believe that the phrase "supporting its internal area reliability" should be further clarified in some way. The inclusion of the undefined concept of "supporting internal area reliability" creates undue compliance risk, since auditors could potentially find an entity non-compliant if no SOLs have been identified as "supporting its internal area reliability". With no clarification, it is conceivable that every SOL on a TOP's system could be considered to support its "internal area reliability". Communicating all SOLs would inundate the RC with unneeded information, which we believe would be detrimental to reliability. If this requirement stays in the standard, it needs to be reworded to indicate that any SOLs identified are identified at the sole discretion of the TOP.

Organization	Yes or No	Question 1 Comment
		o R8 - Change the phrase “as supporting” to “in support of”. o R9 - Strike the word “would” and add an “s” to “cause”.
Response: R1: Comments on the definition should be sent to Project 2006-06 the next time it posts. This project utilizes the proposed definition in a generic manner. No change made. R3 & R5: No tool other is specified in this standard and the modeling requirements for a Transmission Operator have not been changed by this standard. The Transmission Operator will be judged on the merits of its model elsewhere and would simply be applying that model here. No change made. R4: There is nothing in this standard that precludes a Transmission Operator from obtaining approval to take action if such approval is necessary. No change made. R6: While no one may be positively impacted there are any number of entities that won’t be impacted at all. ‘Negatively’ was added at the request of previous commenters and seems appropriate to the SDT. No change made. R6: NERC registered entity was added to the requirement due to comments in previous postings where commenters were concerned about limiting the reach of the requirement to non-NERC entities. The SDT believes that it is clear that messages are to be sent to appropriately identified entities. R8: The reason for the notification is that the specified SOLs are to be treated differently than other SOLs. The SDT believes that the Transmission Operator is uniquely qualified to determine such SOLs. No change made. R8 & R9: The SDT sees no additional clarity being provided by the suggested wording changes. No change made.		
ReliabilityFirst Corporation	Abstain	ReliabilityFirst abstains and offers the same comments as submitted via the previous comment posting period.
Response: The SDT points RFC to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
Seattle City Light	Affirmative	The SDT made changes to TOP-001-2 in response to industry comments and the Quality Review. This includes all aspects of this standard - requirements, measures, and data retention. Do you agree with the changes the drafting

Organization	Yes or No	Question 1 Comment
		team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 Yes Comments: R4. calls for rendering emergency assistance as requested and available to other TOPs, provided that the requesting entity has implemented its "comparable" emergency procedures. The word "comparable" is not very well defined so for example, if the requesting entity implemented load shedding to reduce line loading below SOL, would this requirement obligate the entity asked for assistance to shed its load as well because the load shedding option is almost always available? Please state the requirement more clearly. R11. calls for each Transmission Operator to act or direct OTHERS to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's Tv, or of an SOL identified in Requirement R8, yet there are no requirements directing OTHERS to COMPLY with these directives. R.1 requires BA, GOP, DP and LSE to comply with the reliability directives issues by ITS Transmission Operator, but not by OTHER Transmission Operators. There could also be potential for confusion and double jeopardy if there are competing transmission paths or facilities supporting reliability internal to the Transmission Operators. It should be the Reliability Coordinator task to direct OTHERS to act to mitigate SOL violations.
Response: Comparable is a well defined term and the Webster's use is in play here. Comparable does not mean exactly and leaves the entity some flexibility in how to react. No change made. Requirement R1 does require compliance. The use of the term 'its' is appropriate as a transmission Operator can't issue orders to a Balancing Authority that is outside of its area. If such an order was deemed necessary, it would have to be relayed by that Balancing Authority's Transmission Operator thus 'its' is the appropriate term. No change made.		
ISO New England, Inc.	Affirmative	TOP-001 Standard uses an undefined term "Reliability Directive" which is

Organization	Yes or No	Question 1 Comment
		being proposed in the Reliability Coordinator Standards project. We believe that NERC should post these inter-related projects simultaneous in order to achieve industry support to move these important projects forward. If the RTO Project is approved, it should only be presented to the BOT simultaneously with an approved RC Standards project. Additionally, if the definition of "Reliability Directive" is modified in any way in the Reliability Coordinator Standards project, this would be a material change to this standard and could result in company's filing comments in opposition to FERC.
Response: As has been explained previously, the SDT is working closely with the RC SDT that is responsible for defining the term 'Reliability Directive'. The use of that term within this standard is somewhat generic in nature. The SDT believes that the progress in developing the definition is sufficient to warrant continued progress of Project 2007-03 without significant concerns of wasted effort or time. No change made.		
City Utilities of Springfield, Missouric	Negative	City Utilities of Springfield, MO supports the comments from SPP.
Southwest Power Pool, Inc.	Affirmative	We continue to disagree with the successive ballot process that forces entities to decide on a voting position concurrent with the submittal of comments on the same. NERC needs to explore other ways to expedite the voting/comment process without forcing industry to have faith that changes will be made after approval. Although SPP votes in favor of this standard, we have outstanding comments that should be addressed. We have submittted them in the standards processs and reiterate some of them here. The Purpose Statement is too general and does not provide any direction of how the proposed standard will meet its stated intent. As written the Purpose Statement is applicable to any NERC standard that exists or can be imagined. We suggest additional wording of how this particular standard intends to do what it intends to is needed. For example, "...by requiring

Organization	Yes or No	Question 1 Comment
		applicable entities to have the data necessary to perform reliability analyses and real-time monitoring." While we agree with what we believe to be the intent of R9, using the word "continuous" without sufficient context remains ambiguous so as to prevent clear interpretation by all parties. We would suggest replacing the word "continuous" in R9 with "applicable". The timing criterion associated with an SOL should be associated with the timing criterion of the Facility Rating or Stability criteria. The revised requirement would read: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for the applicable duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
Response: The SDT is a process user and does not determine the elements of the process. If the commenter has problems with the successive ballot concept, it should be directed to the NERC Standards Committee. The stated changes to the Purpose Statement have no relevance to TOP-001-2. No change made. The SDT does not see where any additional clarity has been added by the suggested change. No change made.		
Southwest Transmission Cooperative, Inc.	Affirmative	We generally agree with TOP-001 and the changes since the last posting. However, we continue to believe that use of the language “know or expected to be” in Requirement R3 is confusing and that this is a case where brevity is more effective in communicating the requirement. We believe striking this clause will improve the clarity of the requirement. As the clause is written now, it is not clear to whom it applies? We assume the SDT intended for the notification to be based on the expectation or knowledge of the TOP to whom the requirement applies. However, the clause is not clear on this but is rather a statement that appears to be some general knowledge or expectation. This opens the possibility of an auditor substituting their expectation or knowledge over the applicable TOP. Requirement R5 has a similar issue.

Organization	Yes or No	Question 1 Comment
		We are concerned that the examples listed in Requirement R5 may be too simplistic and could be interpreted too literally. A change in load is one example. Thus, a simple reading of the requirement would imply that a Transmission Operator that has a 1 MW change in a 10,000 MW would be required to notify the Reliability Coordinator. Clearly, that is not what is intended. To resolve this issue, two solutions could be applied. One solution would be to state that changes must be significant. A second solution would be to strike the examples altogether. Requirements R10 and R11 are inconsistent. Requirement R10 states the Transmission Operator must inform the RC of “its actions” to mitigate an IROL or SOL that has been exceeded while Requirement R11 compels the Transmission Operator “to act or direct others to act” to mitigate an IROL or SOL that has been exceeded. While we consider that a Transmission Operator directing others to act is the same as taking action itself, it would appear Requirement R11 does not consider directed actions as the actions of the Transmission Operator. This would imply that Requirement R10 does not include communication of the directed actions since it applies to Transmission Operator actions. However, we do not believe exclusion of Transmission Operator actions was intended in Requirement R10. The simplest solution to align these two requirements more closely would be to change “its” in Requirement R10 to “the”. In this way, Requirement R10 is not limited to only the actions taken directly by the Transmission Operator. The language in the Data Retention section regarding Requirements R7 and R9 needs to be made more consistent with the requirement. We are concerned that language could be interpreted as compelling the Transmission Operator to retain data for any IROL that is temporarily exceeded for a duration less than Tv or an SOL that is exceeded for a time that does not violate the criteria upon which it is based. Neither of these instances would represent a violation of either Requirement R7 or R9. Thus,

Organization	Yes or No	Question 1 Comment
		the data is not necessary to be retained. Under the Compliance Enforcement Authority section, we suggest “entities” in the first bullet and “functional entities” in the second bullet should be changed to “registered entities”. This will make them consistent with one another and the function model. The “Reliability Functional Model Technical Document” describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.
Response: R3 & R5: The SDT disagrees. By utilizing the results of the required Operational Planning Analysis, the Transmission Operator will know what other entities are known or expected to be affected. Striking the clause will not provide clarity but open up other questions. No change made. R5: The use of the term ‘significant’ would not provide any additional clarity as it is still an objective term open to interpretation. Merely striking the examples does not provide additional clarity either as it leaves the situation completely open to interpretation. The SDT believes that including the examples is the best way to go. Any auditor trying to use a 1 MW change on a 10,000 MW system will be hard-pressed to justify their actions. No change made. R10: The SDT disagrees. If the commenter accepts that directing others to act is the same as taking action itself, then the SDT asserts that Requirement R10 is perfectly in line with Requirement R11. No change made. Data retention: The SDT believes that by incorporating a reference to the requirements in question within the data retention language that the concern expressed by the commenter is not an issue. No change made. CEA: The SDT is using language here that has been utilized in multiple standards projects to date and was supplied by staff as accepted language. Furthermore, the SDT does not believe that the suggested changes will provided any additional clarity. No change made.		
Progress Energy	Yes	: Progress Energy requests the removal of the word “identified” in association with Reliability Directive in all Requirements and Measures. Communications between Transmission Operators and other functional

Organization	Yes or No	Question 1 Comment
		entities already require 3-part communications; having to state 'This is a Reliability Directive' to each entity and receive confirmation of that back from each entity, especially across a fleet of Generator Operators and LSEs, could add unnecessary time before action is taken. Entities should always assume that each directive being given to them is a Reliability Directive and respond accordingly. R1 would read "and Load-Serving Entity shall comply with each Reliability Directive issued by its Transmission Operator...".
Response: The SDT believes that it is imperative that each Reliability Directive be identified as such. The SDT refers the commenter to proposed COM-002-3 where it is clearly stated that each Reliability Directive must be identified as such. The SDT does not believe that such communication will delay a response. No change made.		
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Southern Company Services, Inc.	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Southern Company Generation	Affirmative	Please see comments submitted by Antonio Grayson on behalf of each part of Southern Company.
Mississippi Power	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Southern Company	Yes	R3. The requirement is worded such that it implies that the Transmission Operator has a Transmission Operator. We suggest adding the word "other" so that it reads "shall inform its Reliability Coordinator and other Transmission Operator(s)...."

Organization	Yes or No	Question 1 Comment
		R5. We recommend the following word changes:Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations that are known or expected to result in an Adverse Reliability Impact on those their respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations may include are relay or equipment failures, and changes in generation, Transmission, or Load.
Response: The SDT does not see any additional clarity with the suggested changes. No change made.		
Occidental Chemical	Affirmative	See Ingleside Cogeneration LP comment form
Ingleside Cogeneration LP	Yes	As a GO/GOP, Ingleside Cogeneration LP is subject only to TOP-001-2 R1 and R2, related to compliance with a Reliability Directive. We believe that the SDT has captured the appropriate circumstances for when a Reliability Directive is issued and identified - and the circumstances under which it may be not be possible to accommodate one. Furthermore, we agree with the language added to the corresponding Measures (M1 and M2) specifically allowing an attestation to be supplied to a CEA if a Reliability Directive was not received during the compliance time frame.
ComEd	Affirmative	Voted
Electric Reliability Council of Texas, Inc.	Affirmative	ERCOT supports the SDT's modifications.
Nebraska Public Power District	Affirmative	NPPD joins comments submitted by the Southwest Power Pool (SPP).
Southwest Power Pool Regional Entity	Yes	

Organization	Yes or No	Question 1 Comment
Imperial Irrigation District (IID)	Yes	
Dominion	Yes	
Luminant	Yes	
SPP Standards Review Group	Yes	
Arizona Public Service Company	Yes	
Independent Electricity System Operator	Yes	
City of Austin dba Austin Energy	Yes	
Liberty Electric Power LLC	Yes	
NV Energy	Yes	
American transmission Company	Yes	
FirstEnergy Corp	Yes	
Essential Power, LLC	Yes	
NextEra Energy, Inc.	Yes	
Cowlitz County PUD	Yes	
Response: Thank you for your support.		

2. **The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: The majority of the comments received were requesting clarification or suggesting semantic changes. Clarifications have been provided but the semantic changes were not seen as providing any additional clarity to the standard.

Organization	Yes or No	Question 2 Comment
AEP Service Corp.; American Electric Power	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Bonneville Power Administration	Negative	Comments submitted separately.
Duke Energy	Negative	Comments submitted.
Duke Energy Carolina	Negative	Comments submitted
Florida Municipal Power Agency	Negative	Please see FMPA comments submitted separately.
Lakeland Electric	Negative	"Please see FMPA comments submitted separately"
Response: Thank you for submitting comments. Your comments are addressed below.		
MidAmerican Energy Co.	Negative	TOP-002 R2 uses the same vague language as TOP-001 R8. The wording "special subset of SOLs as defined by the TOP" needs to be added. Otherwise NERC and regional auditors will apply the wording broadly when the intent was for a specific subset of SOLs defined by the TOP. Also see the NSRF comments

Organization	Yes or No	Question 2 Comment
Response: The wording of TOP-002-3, Requirement R2 is intentionally identical with that in TOP-001-2 to ensure consistency on terminology across the standards. The SDT does not believe these words are vague but believes they provide a specific reference for Transmission Operators to work with while allowing those Transmission Operators flexibility in operations. No change made.		
Seattle City Light	Negative	2. The SDT made changes to TOP-002-3 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments. 1 No Comments: R2, calls for TOP to have a plan to prevent exceeding SOLs of facilities identified in TOP-001-2 as “supporting reliability internal to its Transmission Operator Area.” This could cause TOPs to be in conflict with no remedy when there are competing transmission paths or facilities supporting internal reliability. R3 just requires TOP to notify all registered entities identified in R2, but again there is no requirement for those entities to comply with the plan. Is that all that is intended? This Standard could also be very difficult to comply with due to the data retention policy which requires maintaining six months worth of data for system analysis. The system studies requires huge amount of data and to maintain that amount of data for 6 months could be very expensive and complicated. Please reconsider cost vs. benefit of the data retention requirement. 6. If you have any other comments on these standards that you have not already provided in response to the prior questions, please provide them here. Comments: Seattle City Light supports the efforts of the Real Time Operations Standards Drafting Team and approves of the direction proposed in these new TOP Standards. TOP-001 in particular clarifies the definition of Reliability Directive and provides straightforward requirements for reporting outages of relay and communication equipment. We are prepared to vote “affirmative” for all of the new TOP Standards

Organization	Yes or No	Question 2 Comment
		of Project 2007-03 once details as discussed above are addressed and resolved.
Response: R2: The SDT fails to see how the phrase in question will cause conflicts for the Transmission Operator. If there are competing solutions it is the obligation of the Transmission Operator to find the best solution for the reliability of the system. That is true today and it will not change in the future due to this phrasing. All this phrasing does is give the Transmission Operator another tool, namely elevating the status of certain SOLs, to come up with the best solution for reliability. No change made. R3: The SDT believes that Requirement R3 is informational in nature as it is in the planning horizon. Actual 'orders' to implement the plan will be issued at a later time by the Transmission Operator and are covered in other standards such as the proposed TOP-001-2. The SDT believes that the notification in this requirement will provide an opportunity for entities to comment on the plan and thus for the Transmission Operator to fine tune its plan. No change made. Data retention: In this day of cheap storage capability, the SDT does not believe that it will be an onerous burden to retain 6 months of analysis. This amount of storage is also consistent with guidelines provided by NERC staff. No change made.		
Westar Energy	Negative	SDT has not adequately addressed previous comments.
Response: The SDT points Westar to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
Florida Municipal Power Pool	Affirmative	See FMPA comments
Florida Municipal Power Agency	No	The existing TOP-002-2 requires that both the BA and TOP perform current day, next day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document

Organization	Yes or No	Question 2 Comment
		also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". FMPA is aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. IN the meantime, the new TOP standards should include operational planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. FMPA believes that both current-day and seasonal remain important, to cover changes from yesterday's plan (e.g., unplanned outages that have occurred since yesterday's plan), and to coordinate planned outages seasonally. R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2.
City of Vero	No	The existing TOP-002-2 requires that both the BA and TOP perform current day, next

Organization	Yes or No	Question 2 Comment
		day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". FMPA is aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. IN the meantime, the new TOP standards should include operational planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. FMPA believes that both current-day and seasonal remain important, to cover changes from yesterday’s plan (e.g., unplanned outages that have occurred since yesterday’s plan), and to coordinate planned outages seasonally. R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an

Organization	Yes or No	Question 2 Comment
		SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2.
Beaches Energy Services of theCity of Jacksonville Beach, Florida	No	The existing TOP-002-2 requires that both the BA and TOP perform current day, next day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". We are aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. In the meantime, the new TOP standards should include operational

Organization	Yes or No	Question 2 Comment
		planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. We believe that both current-day and seasonal remain important, to cover changes from yesterday's plan (e.g., unplanned outages that have occurred since yesterday's plan), and to coordinate planned outages seasonally. R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2.
Response: The Balancing Authority has one role: To balance Load and resources. A key component of this role is to be able to recover from events that cause imbalance. The commenter intermingles the obligation of the Load-Serving Entity with that of the Balancing Authority. The SDT believes that in order for a Balancing Authority to comply with CPS and DCS and the requirements for emergency plans in EOP that they must plan and therefore a separate requirement is not needed and would actually represent double jeopardy. BAL-001-0.1a, BAL-002-1, EOP-001-0b, EOP-002-3, and EOP-003-1 cover these issues for the Balancing Authority. The standard has not eliminated other planning periods as Operational Planning Analysis covers all of the periods cited. What it does do is mandate a next-day analysis. Current day will be handled in Real-time operations and thus isn't needed in this planning environment. The SDT believes that longer term studies will be run by entities on an as needed basis but that requirements are only necessary for next-day. No change made. Stability Limit is a defined term in the NERC Glossary. IROLs and SOLs represent only part of what the Operational Planning Analysis (OPA) is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. No change made.		

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	No	BPA appreciates the drafting team's response to our previous comments and recommends additional clarification: Previous Comments: Given the potential uncertainty regarding how many day ahead studies may be required, BPA suggests adding more clarity to the standard TOP-002-3 to address. BPA recognizes that various regions experience peak operations at different times of the day, anticipated generation patterns shift over the course of the day; and transmission facilities of service start and stop times associated with planned maintenance and construction work at various times throughout the day. Hence, due to these multiple shifts in forecast system conditions, it is unclear whether more than one study is required to meet the requirements of this standard. Additional New Comments:Many entities tend to perform system studies more than one day ahead. Please specify the threshold at which a prior study would have to be updated to meet the next day study requirement. BPA suggests alternate language for the requirement ...something along the lines of ... An entity or TOP may perform a study more than one day in advance; they shall update the study if system conditions (such as line outages, etc.) changed such that there was more than a 5% change in the system operating limit, thereby requiring the need to rerun the study.
Response: There is no mandate in the standard regarding how many studies need to be performed. The requirement is for a valid analysis. If one study can get that done, then one study is sufficient. If conditions change, the SDT expects that the Transmission Operator will conduct another study to analyze the new conditions as the 'old' analysis would no longer be valid. The SDT believes that there is no single value applicable on a continent-wide basis that could be placed in a requirement and that the Transmission Operator is best suited to determine when a new analysis needs to be performed. No change made.		
Consumers Energy	No	This standard gives the TOP more direct authority than is in the MISO process today. The market has means to accommodate this operation. In R3, this may conflict with the present logic our TOP follows concerning their operation in the area of communicating conditions to Generation Operators and other Market Participants. We do not support this standard as written.

Organization	Yes or No	Question 2 Comment
Response: The commenter has failed to provide details on how Requirement R3 conflicts with policy so the SDT is unable to comment in that regard. However, the SDT wishes to point out that Requirement R3 does not require that the entire plan be sent to all entities – just that entity's role in the plan. No change made.		
Southwest Transmission Cooperative, Inc.	Affirmative	We generally agree with the changes to the standard. However, we have identified the following concerns. TOP-001-2 R8 implies the Transmission Operator must look for SOLs that are not IROLs in its Operational Planning Analysis that must be completed per TOP-002-3 R1. There is no such requirement in TOP-002-3 R1 or any other requirement that compels a Transmission Operator to look for these SOLs that are not IROLs. Thus, the SDT needs to clarify if a Transmission Operator is required to look for these SOLs that are not IROLs in the Operational Planning Analyses and why they are not referenced in TOP-003-2 R1. If the SDT did not intend for a Transmission Operator to be required to look for these SOLs that are not IROLs, then it needs to refine TOP-001-2 R8 to be clear that the Transmission Operator may not have a need for these SOLs that are not IROLs. TOP- 002-3 R2 further confuses the situation by referring to the SOLs that are not IROLs that are identified in TOP-002-3 R1 rather than TOP-001-2 R8. Under the Compliance Enforcement Authority section, we suggest "entities" in the first bullet and "functional entities" in the second bullet should be changed to "registered entities". This will make them consistent with one another and the function model. The "Reliability Functional Model Technical Document" describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity. We disagree with the inclusion of voice recordings as an example of the type of evidence that might be retained for TOP-002-3. Operational Planning Analyses are typically conducted in a back office where communications would not be recorded. This might create the impression that there is now a requirement to record such

Organization	Yes or No	Question 2 Comment
		conversations. Recording of these conversations could mute much of the discussion that occurs among personnel performing these studies and working to resolve issues identified in them. Also, the three months retention period is not consistent with the change made to the retention period in TOP-001-2. It was changed to 90 days for voice recordings.
ACES Power Marketing	No	We generally agree with the changes to the standard. However, we have identified the following concerns. TOP-001-2 R8 implies the Transmission Operator must look for SOLs that are not IROLs in its Operational Planning Analysis that must be completed per TOP-002-3 R1. There is no such requirement in TOP-002-3 R1 or any other requirement that compels a Transmission Operator to look for these SOLs that are not IROLs. Thus, the SDT needs to clarify if a Transmission Operator is required to look for these SOLs that are not IROLs in the Operational Planning Analyses and why they are not referenced in TOP-003-2 R1. If the SDT did not intend for a Transmission Operator to be required to look for these SOLs that are not IROLs, then it needs to refine TOP-001-2 R8 to be clear that the Transmission Operator may not have a need for these SOLs that are not IROLs. TOP-002-3 R2 further confuses the situation by referring to the SOLs that are not IROLs that are identified in TOP-002-3 R1 rather than TOP-001-2 R8. Under the Compliance Enforcement Authority section, we suggest “entities” in the first bullet and “functional entities” in the second bullet should be changed to “registered entities”. This will make them consistent with one another and the function model. The “Reliability Functional Model Technical Document” describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity. We disagree with the inclusion of voice recordings as an example of the type of evidence that might be retained for TOP-002-3. Operational Planning Analyses are typically conducted in a back office where communications would not be recorded.

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		This might create the impression that there is now a requirement to record such conversations. Recording of these conversations could mute much of the discussion that occurs among personnel performing these studies and working to resolve issues identified in them. Also, the three months retention period is not consistent with the change made to the retention period in TOP-001-2. It was changed to 90 days for voice recordings.
Brazos Electric Power Cooperative, Inc.	Negative	Additional clarification is necessary that warrants our negative vote. See the issues raised in the comments by ACES Power Marketing.
Response: The SDT expects the SOLs in question to come out of the analysis performed in Requirement R1 but does not believe that the requirement needs to explicitly tell the Transmission Operator that. It is part and parcel of the analysis function. No change made. CEA: The SDT is using language here that has been utilized in multiple standards projects to date and was supplied by NERC staff as accepted language. Furthermore, the SDT does not believe that the suggested changes will provided any additional clarity. No change made. Since this is a notification requirement, voice recordings are an appropriate type of evidence.		
AEP	No	In the previous comment period, AEP requested clarification on whether these requirements are in regards to pre-contingency monitoring or instead based on real-time flow. AEP assumed this was based on Real Time Flow, but we encouraged the drafting team to provide clarifying language to make it more clear to the reader. The drafting team responded by noting that “TOP-002-3 is about Operations Planning, thus it cannot be addressing actual Real-time flow” and “It addresses those flows contained in the Operational Planning Analysis (OPA) and the assessment thereof.” However, no such clarifying language was added to the standard. As stated in our response to Question #1, industry has provided comments to standard drafting teams in an effort to help avoid CANs, Interpretation Requests, and to increase the consistency of interpretation by both CEA’s and industry. And once again, while the team provided insight in their comments, the resulting lack of changes to the standard

Organization	Yes or No	Question 2 Comment
		still leave unnecessary ambiguity that could be easily addressed. Ambiguity of any kind deters from, rather than promotes, the reliability of the BES. Until such clarification is added to the standard itself, AEP cannot support the drafting team's efforts in revising TOP-002-3. Rather than using terms such as "real-time flow", we recommend using "projected post-contingency" and "projected pre-contingency".
Response: The SDT believes that the definition of IROL speaks for itself and therefore that no further explanation is required within the standard. No change made. The SDT sees no additional clarity from the suggested change. No change made.		
Duke Energy	No	o R2 - Consistent with our comment above on TOP-001-2 Requirement R8, the phrase "supporting its internal area reliability" should be further clarified in some way. Also, change the phrase "as supporting" to "in support of".
Response: The SDT believes that the Transmission Operator is uniquely qualified to determine such SOLs and that no further clarification is necessary. No change made. The SDT sees no additional clarity being provided by the suggested wording changes. No change made.		
Oncor Electric Delivery	No	Oncor agrees that the Operational Analysis Plan should be properly communicated, but that it should not be the role of the Transmission Operator to determine who is or who is not NERC Registered.
Response: NERC registered entities can easily be looked up and the SDT does not believe this is an onerous burden. This requirement as worded currently relieves the Transmission Operator of the obligation to notify entities that are not registered with NERC. No change made.		
Southern Company	No	R3- Southern understands the intent of this requirement is to notify all registered

Organization	Yes or No	Question 2 Comment
		entities that may be affected by a mitigation plan for the next day so they can be prepared to respond. However, in some cases like the one shown in the example below, it is unreasonable to expect the TOP to notify every GOP that could be re-dispatched. Requiring this would actually put the system at risk as the TOP would be focused on notifying GOPs inside its TOP area and potentially outside its TOP area and not focused on operating the system.Southern suggests that the requirement be changed to state that the TOP will notify “other TOP’s and associated RC(s) associated with actions in the plan(s)” in a similar manner that other TOPs and RCs are notified in the proposed TOP-001-2, R3 and R5. If that is unacceptable to the SDT then it is suggested at a minimum that “all NERC registered entities” be clarified with the addition of the word “explicitly” just prior to” identified in the plan(s)”.Example: An SOL is identified in the Operational Analysis for the next day from R2. The plan to mitigate this SOL is to call an IDC-TLR. The level of the TLR may or may not reach level 5. If the TLR reaches level 5 many generators will be required to be re-dispatched inside and outside of the TOPs area. This requirement will require the Transmission Operator to notify every Generator Operator that could possibly be re-dispatched for a TLR-5.Another concern with having the TOP notify all entities (which would include those outside their area) is the added FERC Standards of Conduct risk that the NERC standard is forcing the TOP to assume. For example, notification may go to a GOP which also performs market functions about which the TOP is unaware. In communicating the plan to the GOP, the TOP may inadvertently communicate non-public transmission information in violation of the Standards of Conduct. If communications is limited to external entities that are TOP and RC, this risk is eliminated and the communication to the GOP will take place by its native TOP - which should be familiar with any Standards of Conduct restrictions on communication to the GOP.

Response: The SDT believes that all entities that have a role in the plan need to be notified or the eventual implementation of the plan could be compromised. The requirement only stipulates that an entity receive notice of their role in the plan so there should be no fear of inadvertently providing sensitive information to an entity that shouldn’t have such information. No change made.

Organization	Yes or No	Question 2 Comment
ReliabilityFirst Corporation	Abstain	ReliabilityFirst abstains and offers the same comments as submitted via the previous comment posting period.
Response: The SDT points RFC to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
American Transmission Company, LLC	Affirmative	Comments submitted.
Florida Power Corporation	Affirmative	comments submitted
FirstEnergy Energy; FirstEnergy Solutions	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Manitoba Hydro	Affirmative	Please see comments submitted by Joe Petaski (Manitoba Hydro)
Mississippi Power	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Progress Energy; Progress Energy Carolinas	Affirmative	"comments submitted"
Southern Company Generation; Southern Company Services, Inc.	Affirmative	Please see comments submitted by Antonio Grayson on behalf of each part of Southern Company.
Ohio Edison Company	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.

Organization	Yes or No	Question 2 Comment
Response: Thank you for submitting comments. Your comments are addressed below.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power; Tacoma Public Utilities	Affirmative	The term “anticipated … Contingency event conditions” in R1. is not a NERC defined term and could be interpreted as requiring analysis of all contingencies including extreme events. The requirement should clarify if it only applies to certain types such as category P1 or whether each TO can independently select which types of contingencies they anticipate. One suggested form or rewording the requirement could be: R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal conditions and TPL-001-2 category P1 Single contingencies.
Response: The SDT believes that more than just single Contingencies need to be studied in order to have a viable plan. Extreme events are a separate item in the planning standards and would not be included here. No change made.		
Sacramento Municipal Utility District	Affirmative	Per discussion held at the NERC Standards Committee meeting in April, NERC Staff indicated changes would be made to the reference of "bulk power system" to "Bulk Electric System" would be changed on certain pertinent standards. This appears to be such a case.
Response: Neither of those terms is used within this standard. No change made.		
City of Austin dba Austin Energy	Yes	TOP-002-3, R1TOP-002-3, R1 states “Each Transmission Operator shall have an Operational Planning Analysis ...” and the mapping document says that this requirement “is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator.” As such, Austin Energy suggests that the language in TOP-002-3, R1 be changed from “... shall have an Operational Planning Analysis ...” to “... shall perform an Operational Planning Analysis ....” This language matches IRO-008-1, R1 and better aligns with Measure 1 for TOP-002-3.

Organization	Yes or No	Question 2 Comment
Response: The language in Requirement R1 is intentional to allow for the use of a previously completed Operational Planning Analysis if it is still viable. No change made.		
Dominion	Yes	TOP-002-3 M2 should be updated to reflect the changes made in R2 (as suggested below).M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include but it is not limited to plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis. VSLs R2 (page 5 redline version) Severe Column should be updated to reflect the changes made in R2 (as suggested below).The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.
Response: The SDT sees no additional clarity being provided with the suggested change. No change made.		
Manitoba Hydro	Yes	Section 1.3 Data Retention - For consistency with TOP-001-2, the retention period for voice recordings in TOP-002-3 should be changed from 3 months to ‘ninety calendar days’.
Response: Your suggested change has been made.		
Progress Energy	Yes	Please change the R2 VSL from “supporting its internal area reliability” to “supporting reliability internal to its Transmission Operator Area...”.

Organization	Yes or No	Question 2 Comment
Response: The SDT sees no additional clarity being provided with the suggested change. No change made.		
Idaho Power Company	Yes	I agree with the direction of the project. Consolidating all the TOP standards and eliminating the redundancy will make it much easier.
Cowlitz County PUD	Yes	This Standard is not applicable to Cowlitz PUD and the District will abstain in the ballot. However, this commenter sees no problems with the changes.
Nebraska Public Power District	Affirmative	NPPD joins comments submitted by the Southwest Power Pool (SPP).
ComEd	Affirmative	Voted
Consolidated Edison Co. of New York	Affirmative	See NPCC group comments
Electric Reliability Council of Texas, Inc.	Affirmative	ERCOT supports the SDT's modifications.
American transmission Company	Yes	
Arizona Public Service Company	Yes	
FirstEnergy Corp	Yes	
Imperial Irrigation District (IID)	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 2 Comment
Occidental Chemical	Affirmative	See Ingleside Cogeneration LP comment form
Ingleside Cogeneration LP	Yes	
ISO New England Inc	Yes	
Kansas City Power & Light	Yes	
Liberty Electric Power LLC	Yes	
Luminant	Yes	
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NSRF for LES' concerns.
Great River Energy	Affirmative	Great River Energy agrees with the comments of the MRO NSRF
MRO NSRF	Yes	
New York Independent System Operator	Yes	
NextEra Energy, Inc.	Yes	
NV Energy	Yes	
Southwest Power Pool Regional Entity	Yes	
SPP Standards Review Group	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 2 Comment
Xcel Energy	Yes	
Response: Thank you for your support.		

3. The SDT made changes to TOP-003-2 in response to industry comments and the Quality Review. This includes all aspects of this standard – requirements, measures, and data retention. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The comments received requested clarification or suggested semantic changes. The SDT has provided clarifications where requested. The semantic changes were not seen as providing any additional clarity to the requirements and have not been accepted. One change was made to Requirement R2, Part 2.1 to improve consistency between the requirement and the part in response to industry comments.

Part 2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

Organization	Yes or No	Question 3 Comment
AEP Service Corp.; American Electric Power	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Cowlitz County PUD	Negative	Comment submitted.
Florida Municipal Power Agency	Negative	Please see FMPA comments submitted separately.
Kansas City Power & Light Co.	Negative	Comments and concerns with the proposed standards have been expressed within the NERC comment form
Lakeland Electric	Negative	"Please see FMPA comments submitted separately"
Omaha Public Power District	Negative	OPPD supports MRO and SPP RTO comments. Please see comments from Doug Peterchuck.
Response: Thank you for submitting comments. Your comments are addressed below.		
City of Garland	Negative	The requirements should be written such that they will support VSL levels of Lower,

Organization	Yes or No	Question 3 Comment
		Moderate, and High - not Severe only for R5. It should take minimal requirement sentence strucuring to allow for all VSL levels to be assigned
Response: The SDT believes that the severity of not fulfilling an entity's obligations for this requirement warrant a single severe VSL. No change made.		
East Kentucky Power Coop.	Negative	The standard as proposed does not appear to comply with the stated intent of Project 2007-03, that being: "The industry needs clearer, unambiguous and enforceable standards in order to effectively operate the Bulk Electric System." Not only are the changes to TOP-003 as vague—or ambiguous--if not more so than the previous TOP-003-1 standard, the requirements do not provide for any consistency between companies. For example, who between two parties determines, or in the case of an inability to reach agreement, who is responsible for arbitrating an agreement when two neighboring entities are attempting to establish a "mutually agreeable format". Resolution could be problematic when required changes to a format between entities A and B would require format changes between entities A and C, A and D, and A and E, and would potentially require entity A to maintain several different format standards to meet the requirements for coordination between entities B, C, D, and E. Many items previously in TOP-003-1 appear to have been completely abandoned in lieu of much less prescriptive specifications in TOP-003-2. For example, clear provisions regarding timing of data availability listed in TOP-003-1 are not specified in any form in TOP-003-2 other than to require that entities needing to share data essentially "work it out amongst themselves". The standard needs to better guide entities in regard to the type of data—at a minimum—they SHOULD be requesting and obtaining. Alternately, such format specifications should be left to the authority of the RC to coordinate among TO/BA entities for which they are responsible.

Organization	Yes or No	Question 3 Comment
Response: The SDT asserts that existing arbitration procedures can, and will be, used to resolve conflicts. No change made. Format agreements between A and B will not affect formats between A and C and vice versa. It is true that a Transmission Operator or Balancing Authority may need to support multiple formats but that is no different than it is today. No change made. The SDT believes that the requirements are sufficiently prescriptive without inhibiting needed flexibility in devising solutions. Mutual agreement amongst affected entities is a better solution in the long run than trying to force a one-size-fits-all approach to the problem. No change made. The concept of the data specification is that the Transmission Operator and Balancing Authority are in the best position to determine what data they need to perform their duties. This is in alignment with the approved IRO standards for the Reliability Coordinator. No change made. The Reliability Coordinator will be the final arbitrator on disputes but the SDT believes that it would be detrimental to the work of the Reliability Coordinator for them to be involved in each and every agreement if it isn't necessary. No change made.		
INTELLIBIND	Negative	The Requirements are confusing and refer to other requiremtns. The original concept was that requirments shall stand alone, and not be dependent on other requirments or standards. Violation of R1 or R2 will cascade to addtional violations based on the structure of the Standard. These issues should be repaired as a part of this revision.
Response: The requirements do stand alone and are not dependent on other requirements. There are simple references to other requirements in Requirement R5 but no dependence. Each requirement stands alone and the VSLs follow suit so there are no cascading violations. No change made.		
Seattle City Light	Negative	While the idea of making each BA and TOP formally outline a data specification for all the information it needs to perform its Operational Planning Analysis is a worthy concept, the requirements in this Standard for evidence and data retention are onerous. Specifically the requirement to retain all electronic or hard copies of data transmittals or retain attestations from all receiving entities would require a tremendous amount of resources to be compliant. It may also be technically impossible to comply with these requirements because the data specifications developed individually by each entity may not be compatible with each other. The

Organization	Yes or No	Question 3 Comment
		formats and periodicity of data collected by each entity may not be compatible with the specifications and it could be impossible to comply with these requests without major changes to the infrastructure. As an alternative, most of the NERC registered entities are currently required to provide that data to their Reliability Coordinators (RC) using the specifications already developed by the RCs and that data could be used by the TOPs and BAs to perform their functions. Seattle City Light supports the efforts of the Real Time Operations Standards Drafting Team and approves of the direction proposed in these new TOP Standards. We are prepared to vote “affirmative” once details as discussed above are addressed and resolved.
Response: The SDT believes that it is counter-productive to involve the Reliability Coordinator in data transfers that are simply pass-through transfers and also believes that not all of the data required by a Transmission Operator or Balancing Authority will be available from the Reliability Coordinator in every instance. There is nothing in the standard that requires the retention of every data transmittal. Once an entity has provided evidence that they are supplying the data, the measure has been fulfilled. This should not be an onerous task. No change made.		
Westar Energy	Negative	SDT has not adequately addressed previous comments.
Response: The SDT points Westar to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
AEP	No	In the previous comment period, AEP suggested that R5 be modified so that it does not unintentionally create an edict to provide “any data” to parties simply because R5 could be interpreted as allowing requests of any kind. The SDT responded by stating that “Requirement R5 is bound by the constraints of Requirements R1 and R2 so that not just any information can be requested.” AEP does not see any explicit constraints specified in R1 or R2, and even if constraints were noted there, see nothing that would indicate those constraints would also apply to R5. At the most, the only possible constraint could be the “mutually agreeable format”, however that would seem to provide no bounds or constraints on the kind or amount of data being requested. We suggest providing further clarification that what has been mutually

Organization	Yes or No	Question 3 Comment
		agreed to by the parties involved, goes beyond simply the format of the data. In addition, it needs to be made clear that those constraints also apply to R5. Until such clarification is added to the standard itself, AEP cannot support the drafting team's efforts in revising TOP-003-2.
Response: Requirement R1 clearly limits the data to that needed to support Operational Planning Analysis and Real-time monitoring. The SDT believes that this sufficiently limits the type and amount of data that can be requested. Requirement R5 is tied to the data specifications delivered in Requirements R3 and R4 so the limitations carry through. No change made.		
Florida Municipal Power Pool	Affirmative	See FMPA comments
Beaches Energy Services of theCity of Jacksonville Beach, Florida	No	Related to the BA performing a day-ahead plan discussed in FMPA's response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.
City of Vero	No	Related to the BA performing a day-ahead plan discussed in FMPA's response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead

Organization	Yes or No	Question 3 Comment
		as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.
Florida Municipal Power Agency	No	Related to the BA performing a day-ahead plan discussed in FMPA's response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.
Response: The Balancing Authority has one role: To balance Load and resources. A key component of this role is to be able to recover		

Organization	Yes or No	Question 3 Comment
from events that cause imbalance. The commenter intermingles the obligation of the Load-Serving Entity with that of the Balancing Authority. The SDT believes that in order for a Balancing Authority to comply with CPS and DCS and the requirements for emergency plans in EOP that they must plan and therefore a separate requirement is not needed and would actually represent double jeopardy. BAL-001-0.1a, BAL-002-1, EOP-001-0b, EOP-002-3, and EOP-003-1 cover these issues for the BA. The data specification concept has already been approved by FERC for Reliability Coordinators in the IRO standards. No change made.		
Consumers Energy	No	The standard as written is more vague than the current TOP-003. It follows the logic of IRO-010 and talks about specification documents instead of actions that need to be taken. We do not support this standard as written.
Response: The data specification concept has already been approved by FERC for Reliability Coordinators in the IRO standards. No change made.		
Cowlitz County PUD	No	After reviewing the industry comments submitted, Cowlitz is respectfully perplexed why comments were not addressed related to lack of recourse the receiving entity of a data specification has if the data specification is unreasonable. The data specification receiving entity must have some recourse to appeal unreasonable obligation requirements short of appealing a violation finding through the RE/NERC/FERC or ultimately a court of law. Due to the undefined nature of what constitutes a reasonable data specification document other than a “mutually agreeable format,” the risk of capricious dictatorial demands having no reliability return is high. The usage of “format” can only encompass the organization, plan, and style of the data to be submitted; this can’t be used to limit data submittal to that which is available at a rate of transmittal which is possible. Cowlitz can’t find a remedy for requirement R5 without allowing for some risk of entity intransigent behavior leading to RE or ERO intervention. However, there are current standards that allow, but limit, this risk by defining allowable exceptions. Examples which include such exceptions to requirements are “unless such actions would violate safety...,” contained in several standards; and “unless it provides a reliability reason

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>to the requestor...,” contained in Standard IRO-006-5. Cowlitz suggests the following exemptions: Unless data or information is not available without installation of additional equipment, or can’t be reasonably available due to existing equipment limitations, available personnel limitations, or unexpected equipment failure.</td></tr>
<tr><td colspan="3">Response: The SDT asserts that there are existing arbitration processes that entities can employ short of going to NERC, FERC, or courts. No change made.</td></tr>
<tr><td>Idaho Power Company</td><td>No</td><td>TOP-003 will require that we create a list of data necessary to complete our operational planning analysis. Currently I don't think we have a good process for doing analysis so defining the data required may be difficult.</td></tr>
<tr><td colspan="3">Response: Compliance with this requirement will be mandatory, resulting in the need for the list mentioned by the commenter.</td></tr>
<tr><td>Liberty Electric Power LLC</td><td>No</td><td>Multiple entities commented in the prior round that the standard would expose RE's to violation space in the event of a communications failure. Although the SDT stated in the consideration of comments that "It is not the intent of the SDT that TOP-003-2 penalizes entities for communication errors. The intent is to have the data communications established.", the plain language of the standard is in conflict with this position. The standard as written states a RE "shall satisfy the obligations of the documented specifications for data." Among the specifications of real time data requests are the periodicity of the submission. For example, PJM in Manual 14D, Generator Operational Requirements, states "All data items, regardless of type, are collected and disseminated at the same 2-second rate. Instantaneous MW and MVAR information is collected on the same data scan as Integrated MWh and MVARh." If a RE has a loss of their RTU, they will have failed to "satisfy the obligations of the documented specifications for data", and be exposed to a potential violation.If the intent of the SDT is as stated in the previous consideration of comments, there must be some language to that effect added to the standard. In R1, adding a bullet 1.21 "an alternative format for use in the event of interruption of the mutually agreed format" would close the hole in the language as written and</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		satisfy the stated objections.
Response: Loss of an RTU or other communication problems are covered in the COM standards. This requirement is solely for the set up required to fulfill an entity's data obligations. No change made.		
Luminant Energy; Luminant Generation Company LLC	Negative	See comments submitted by Luminant.
Luminant	No	TOP-003-2 as currently written does not provide any recourse for the entity receiving a data request if that entity feels the data request is unreasonable either in content or timing or if the entity does not have the data available to submit. As such I would recommend modify R5 as follows:R5. Each......shall satisfy the obligations of the documented specification for data. R5.1. If the entity receiving the data request cannot provide the requested data either in content or timing then the entity receiving the data request shall notify the requesting entity and provide a reason for not providing the data.
Response: The SDT asserts that there are existing arbitration processes that entities can employ short of going to NERC, FERC, or courts. No change made.		
Great River Energy	Affirmative	Great River Energy agrees with the comments of the MRO NSRF
American transmission Company	No	Requirement R3 and R4 should specify which entities are required to respond to data requests. For example, a TOP in Indiana who sends a request to a TOP in Wisconsin; should the TOP in Wisconsin be required to respond. ATC recommends that the term "contiguous entity" be referenced and added to the requirements.+
MidAmerican Energy	No	See the NSRF comments
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NSRF for LES' concerns.

Organization	Yes or No	Question 3 Comment
Muscatine Power & Water	Negative	Please see comments submitted by the MRO NSRF
MRO NSRF	No	Requirement R3, and R4 must specify which entities are required to respond to data requests. For example should a TOP in Indiana send a request to a TOP in Wisconsin, must it be complied with. Suggest a, "contiguous entity" reference.Requirements R1 and R3 are very vague and need to add more specificity similar to that from existing standard TOP-005 which includes specific guidelines.
Response: The SDT believes that data requirements may go beyond contiguous entities and that any entity receiving a data specification is obligated to respond. No change made.		
City Utilities of Springfield, Missouri	Negative	City Utilities of Springfield, MO supports the comments from SPP.
Southwest Power Pool Regional Entity	No	SPP RE does not believe TOP-003-2 addresses the requirements in PRC-001.
Response: Without specific comments, the SDT is unable to respond as the SDT believes the requirements are met.		
Texas Reliability Entity	No	1) Overall, this change to TOP-003-2 will cause differences in what each TOP/BA thinks it needs in terms of data, which will be difficult to audit. There should be a minimum set of data that the TOP/BA should address (especially when removing more specific Requirements such as those that are deleted from PRC-001-1.) For example, if a TOP or BA decides not to monitor its SPSs, which is currently required by PRC-001-1, there will be no repercussions from a compliance standpoint, but an impact to monitoring the state of reliability will occur. 2) R1: We suggest adding "analysis functions" after Operational Planning Analysis to fully capture performance requirements for a TOP during Real-Time. 3) R2: We suggest adding "Operational Planning Analyses" in front of "analysis functions". The Operational Planning Analysis, by definition, includes "Expected

Organization	Yes or No	Question 3 Comment
		system conditions such as load forecast(s), generation output levels . . .,” which relate to the Real Power balance requirement that the BA must comply with. A BA should also create a documented specification for the data necessary for it to perform an Operational Planning Analysis, which may include development of integrated operational plans, acquiring reliability-related services from Generator Operators, providing generation dispatch to the Reliability Coordinator, and other responsibilities as dictated by the Functional Model. 4) R3 We suggest adding “analysis functions” after Operational Planning Analysis to fully capture performance requirements for a TOP during Real-Time. 5) R4: We suggest “Operational Planning Analyses” in front of “analysis functions” to be consistent with our comment that R2 should require “Operational Planning Analysis” data in the BA’s data specification. 6) R3 and R4: What is the required time frame required for the TOP and BA to distribute changes to its data specification? We suggest adding a sentence that the TOP or BA must distribute its data specification within 30 calendar days of creation or revision. 7) R5: What is the required time frame for an Entity to satisfy the obligations of the data specification? None is specified. We suggest a time frame of 30 calendar days from the date of receipt to comply with changes to data specifications. 8) The VRF and VSL justification document was inconsistent and unconvincing in several respects related to TOP-003-2 R2. That should be revisited after the requirements are firmed up.

Response: 1. The SDT believes that each Transmission Operator and Balancing Authority will have different requirements for data. That is one of the reasons for the data specification concept. Any omissions in the data specification will be filtered out by the inability of the Transmission Operator or Balancing Authority to fulfill their obligations and should therefore be quickly rectified. Any penalties associated with such omission would thus be picked up in the other standards associated with those duties. No change made.

Organization	Yes or No	Question 3 Comment
2. The SDT sees no additional clarity being provided with the suggested change. No change made. 3. Requirement R1 previously included both the Transmission Operator and Balancing Authority. However, multiple comments in previous postings pointed out that Balancing Authorities do not perform Operational Planning Analyses and thus the requirement was split as it is now shown. No change made. 4. The SDT sees no additional clarity being provided with the suggested change. No change made. 5. Balancing Authorities do not perform Operational Planning Analyses. No change made. 6. The SDT sees no additional clarity being provided with the suggested change. The timeframe is essentially determined in Requirements R1, Part 1.4 and R2, Part 2.4. No change made. 7. Requirements R1, Part 1.4 and R2, Part 2.4 identify the timeframe involved. No change made. 8. Without specific comments, the SDT is unable to respond.		
ReliabilityFirst Corporation	Abstain	ReliabilityFirst abstains and offers the same comments as submitted via the previous comment posting period.
Response: The SDT points RFC to the responses posted for the previous posting. Without any further specific comments, the SDT has no further responses to offer.		
PNGC Group Comments		Comments: In addition to the same Applicability argument we made in Question 1 for TOP-001-2, the PNGC comment group has a couple of minor issues with TOP-003-2:1. We question the Violation Risk Factor (VRF) of “Medium” for R5. R1-4 have VRFs of “Low” so the “Medium” designation for R5 seems unwarranted. If the SDT views the failure of TOPs and BAs to distribute data requests to other entities in an agreeable format as a “Low” risk, then the failure of those other entities to respond to issued data requests should also be a “Low” risk. We believe R1-5 should all have a “Low” VRF. 2. R1 and R2 require the BA and TOP create a documented specification for data needed to perform analysis functions and Real-time monitoring. We question R1.2 and R2.2: “A mutually agreeable format.” There absolutely should be a mutually

Organization	Yes or No	Question 3 Comment
		agreeable format for the data but the standard doesn't define how that is to be accomplished. It seems to us that the TOP and BA will just issue the directive without consultation and that violation of R1.2 and R2.2 by the TOP or BA is unenforceable. We suggest expanding M1 and M2 to include acknowledgement by entities that are the subject of requests. The acknowledgment should include that the request was received and the data format is agreed to.
Response: Requirements R1 through R4 all represent actions that are taking place 'ahead' of time. Therefore, there is some flexibility regarding them. Requirement R5 is the actual supply of data and there is no slack involved. No change made.		
Kansas City Power & Light		There is no reliability purpose served by an Entity developing and posting specifications of data needed to perform its Operational Planning Analysis and Real-time monitoring. The only reliability action that matters is the request for data specific to other Entities in order to perform analysis and monitor operating conditions. These requirements would be more effective if they targeted the following principles:1. Identify the data needed to perform analysis and effectively monitor operating conditions,2. Identify the Entities that may have data useful to support analysis and monitoring operating conditions and, 3. Seek to obtain the data from other Entities by engaging the other Entities and coming to a mutual agreement regarding data exchange with the Entity. Requirement R5 does not allow for "mutual agreement" as the SDT has suggested in their response to comments from the last draft. As written, this requirement will cause an Entity that is a recipient of a request for data to fail the requirement if a mutual agreement cannot be made. The SDT further states in their response to comments that requirements R1 and R2 ensure disparity between Entities cannot occur. On the contrary, the specifications that are developed as required by these requirements lock an Entity into that specification. If another Entity cannot meet any part of the specification in a data exchange request, there is no recourse in these requirements to relax the specification. The SDT has good intentions, however, these requirements as written

Organization	Yes or No	Question 3 Comment
		do not allow for the flexibility needed in the exchange of data with other parties.
Response: The SDT disagrees. There is a definite reliability benefit to creating the data specifications as they are required in order for the Transmission Operator and Balancing Authority to obtain the data they need to fulfill their responsibilities. The recipient of the data specification must receive clear data requirements or it may fail to provide data necessary to support the reliability reason that instigated the issuance of the data specification. Requirement R5 does not include mutual agreement because that concept is covered in Requirements R1 and R2. The SDT asserts that there are existing arbitration processes that entities that provide adequate recourse if issues can't be resolved. No change made.		
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
American Transmission Company, LLC	Affirmative	Comments submitted.
Duke Energy Carolina	Affirmative	comments submitted
FirstEnergy Energy Delivery; FirstEnergy Solutions	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional comments and suggestions submitted through the formal comment period.
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Manitoba Hydro	Affirmative	Please see comments submitted by Joe Petaski (Manitoba Hydro)
Mississippi Power	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
New York Independent System Operator	Affirmative	Comments have been provided
Ohio Edison Company	Affirmative	FE appreciates the hard work of the standards drafting team. Please see additional

Organization	Yes or No	Question 3 Comment
		comments and suggestions submitted through the formal comment period.
Southern Company Generation	Affirmative	Please see comments submitted by Antonio Grayson on behalf of each part of Southern Company.
Southern Company Services, Inc.	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Response: Thank you for following the instructions on submitting comments. Your comments are addressed below.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	If a Transmission Operator or a Balancing Authority is requesting data from another entity, they must demonstrate a reliability impact validating the need for the requested data.
Response: By limiting data to that specified in Requirements R1 and R2, the SDT believes that only reliability related data will be requested. No change made.		
Nebraska Public Power District	Affirmative	NPPD joins comments submitted by the Southwest Power Pool (SPP).
Southwest Power Pool, Inc.	Affirmative	We continue to disagree with the successive ballot process that forces entities to decide on a voting position concurrent with the submittal of comments on the same. NERC needs to explore other ways to expedite the voting/comment process without forcing industry to have faith that changes will be made after approval. Although SPP votes in favor of this standard, we have outstanding comments that should be addressed. We have submittted them in the standards processs and reiterate some of them here. The Purpose Statement is too general and does not provide any direction of how the proposed standard will meet its stated intent. As written the Purpose Statement is applicable to any NERC standard that exists or can be imagined. We suggest additional wording of how this particular standard intends to do what it intends to is

Organization	Yes or No	Question 3 Comment
		needed. For example, "...through requiring all operating parties who need to take action have the knowledge and obligation to do so." Deleting the requirements from PRC-001 and including them in R1 and R2 of TOP-003-2 raises the question of what other types of data or information need to be included in the specification that do not normally come to mind when considering this type of information. To be sure that all the bases are covered, we would suggest that the SDT provide a guideline which incorporates the types of data and information they envisioned when drafting these requirements. Additionally, incorporating protective relay information in the data specifications of R1 and R2 raises the potential for auditors to question the contents of an entity's specification. Again, guidance is needed on the part of the TOP and BA in developing the specification initially. Could the SDT provide this initial guidance, or list of examples, in the form of a guideline? We have concerns with R1 and R2 being as open-ended as they are, especially since they are followed by the obligation to provide that data contained in R5. For example, how do you resolve issues when a mutual agreement cannot be reached? If an entity feels that the requestor is asking for data that goes beyond what they would reasonably need to perform their analysis, what process is used to resolve the stand-off?
Response: The SDT is a process user and does not determine the elements of the process. If the commenter has problems with the successive ballot concept, it should be directed to the NERC Standards Committee. The SDT believes that the Purpose Statement is direct and to the point and clearly identifies what is required. No change made. The SDT re-iterates its position that the Transmission Operator and Balancing Authority are the best ones to determine the contents of the data specification and that any attempt to provide a minimal list or other guidance would be short-sighted and possibly misleading. The SDT believes that an auditor can only question what is contained in the requirements and in this case that would include only the existence of the data specification and not its contents. Any omissions of data will be caught up in failures to adhere to other standards. No change made. The SDT asserts that there are existing arbitration processes that entities can employ short of going to NERC, FERC, or courts. No		

Organization	Yes or No	Question 3 Comment
change made.		
Tacoma Public Utilities	Affirmative	If a Transmission Operator or a Balancing Authority is requesting data from another entity, they must demonstrate a reliability impact validating the need for the requested data.
Response: By limiting data to that specified in Requirements R1 and R2, the SDT believes that only reliability related data will be requested.		
Brazos Electric Power Cooperative, Inc.	Negative	Additional clarification is necessary that warrants our negative vote. See the issues raised in the comments by ACES Power Marketing.
Southwest Transmission Cooperative, Inc.	Affirmative	Generally, we agree with the standard. However, we have one concern regarding the Data Retention section. The third bullet compels the Transmission Operator to retain evidence for three calendar years that it distributed its data specification. Because the data needs do not change frequently, it is possible that the Transmission Operator will have periods greater than three years in which the data specification was not updated and, thus, not communicated. What data and information would the Transmission Operator use to demonstrate compliance in this situation? Would an attestation be appropriate? If so, the measure should be updated to reflect this. All of the responses to comments regarding concerns of Requirement R5 indicate that the SDT intended for Requirement R5 to apply to the general satisfaction of the data specification and not any specific data points. However, the Data Retention section does not support this view point. It requires retention of 90 days worth of data. Normally, short periods of data are retained when they are expected to be voluminous. Thus, we assume the Data Retention section was anticipating that the actual data supplied would be retained. This seems inconsistent with the concept of generally satisfying the data specification. It would make more sense to have a statement from the Transmission Operator indicating the data specification has been satisfied or documentation of the enabling of data links to demonstrate general

Organization	Yes or No	Question 3 Comment
		satisfaction of the data requirements. Under the Compliance Enforcement Authority section, we suggest “entities” in the first bullet and “functional entities” in the second bullet should be changed to “registered entities”. This will make them consistent with one another and the function model. The “Reliability Functional Model Technical Document” describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.
ACES Power Marketing	Yes	Generally, we agree with the standard. However, we have one concern regarding the Data Retention section. The third bullet compels the Transmission Operator to retain evidence for three calendar years that it distributed its data specification. Because the data needs do not change frequently, it is possible that the Transmission Operator will have periods greater than three years in which the data specification was not updated and, thus, not communicated. What data and information would the Transmission Operator use to demonstrate compliance in this situation? Would an attestation be appropriate? If so, the measure should be updated to reflect this. All of the responses to comments regarding concerns of Requirement R5 indicate that the SDT intended for Requirement R5 to apply to the general satisfaction of the data specification and not any specific data points. However, the Data Retention section does not support this view point. It requires retention of 90 days worth of data. Normally, short periods of data are retained when they are expected to be voluminous. Thus, we assume the Data Retention section was anticipating that the actual data supplied would be retained. This seems inconsistent with the concept of generally satisfying the data specification. It would make more sense to have a statement from the Transmission Operator indicating the data specification has been satisfied or documentation of the enabling of data links to demonstrate general satisfaction of the data requirements.

Organization	Yes or No	Question 3 Comment
		Under the Compliance Enforcement Authority section, we suggest "entities" in the first bullet and "functional entities" in the second bullet should be changed to "registered entities". This will make them consistent with one another and the function model. The "Reliability Functional Model Technical Document" describes a functional entity not as a specific company but rather a specific part of the functional model such as a Balancing Authority. Registered entities are specific companies. For example, SPP is a registered entity that works for their Regional Entity as the Reliability Coordinator functional entity.
Response: The SDT believes that data specifications will change within a 3 year period and thus the situation cited is not relevant. If by some chance the specification didn't change, there are many ways to show that and the SDT doesn't feel that this exception needs to be spelled out in the standard. No change made. Data retention for Requirement R5 does not require that all data be kept for 90 days. It states that an entity must show that they fulfilled the obligation of the requirement. One way to do that would be to keep the data but there are other ways to show it. No change made. The SDT sees no additional clarity being provided with the suggested change. No change made.		
Manitoba Hydro	Yes	R2.1 - For consistency with R2 and completeness, 'analysis functions' should be added to R2.1. Suggested wording: 'A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring'.
Response: The SDT agrees and has made conforming changes to Requirement R2, Part 2.1. **Part 2.1**. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.		
NextEra Energy, Inc.	Yes	NextEra believes additional editing is needed to provide the step-by-step clarity the proposed Reliability Standard seeks to implement. To provide more clarity, NextEra suggests that in R3, R4 and R5 be rewritten as follows: "R3. Consistent with the requirements of R1, each Transmission Operator shall distribute its request for data

Organization	Yes or No	Question 3 Comment
		to each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider that has data required to be used in the Transmission Operator's Operational Planning Analysis and Real-time monitoring process. ""R.4 Consistent with the requirements of R2, each Balancing Authority shall distribute its data request to each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider that has data required to be used in the Balancing Authority's analysis functions and Real-time monitoring process.""R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider that receives a data request pursuant to Requirement R3 or R4 shall provide the requested data."
Response: The SDT sees no additional clarity being provided with the suggested change. No change made.		
NV Energy	Yes	We see no problem with what was changed in this posting; however, please note issues raised related to TOP-003-2 in the comment submitted on Question 6.
Response: Please see response to Q6.		
Occidental Chemical	Affirmative	See Ingleside Cogeneration LP comment form
Ingleside Cogeneration LP	Yes	We are encouraged that the SDT has added a statement in M3 and M4 calling for those TOPs and BAs who post their data specifications to also electronically notify the downstream data suppliers. This is a good first step in the use of a web-based data collection process - which we hope will replace the spreadsheet-based process mostly in place today. A goal of such a system must be to consolidate all operational data requirements into a single template, so that data suppliers are not subject to redundant criteria.

Organization	Yes or No	Question 3 Comment
Bonneville Power Administration	Yes	BPA is in support of this standard due to the importance of being able to receive data.
Consolidated Edison Co. of New York	Affirmative	See NPCC group comments
Electric Reliability Council of Texas, Inc.	Affirmative	ERCOT supports the SDT's modifications.
ComEd	Affirmative	Voted
Arizona Public Service Company	Yes	
City of Austin dba Austin Energy	Yes	
Dominion	Yes	
Duke Energy	Yes	
Essential Power, LLC	Yes	
FirstEnergy Corp	Yes	
Imperial Irrigation District (IID)	Yes	
Independent Electricity System Operator	Yes	
ISO New England Inc	Yes	

Organization	Yes or No	Question 3 Comment
New York Independent System Operator	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
Southern Company	Yes	
SPP Standards Review Group	Yes	
Xcel Energy	Yes	
Response: Thank you for your support.		

4. The SDT is suggesting the retirement of three requirements in PRC-001 since those requirements deal with data handling and can now be incorporated in the data specification concept suggested for TOP-003-2. Do you agree with the changes the drafting team has made? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.

Summary Consideration: The comments received were mainly requesting clarification or suggesting semantic changes. Clarification has been provided where necessary. The semantic changes were not seen as providing additional clarity and have not been incorporated.

One change to the standard was made due to industry comments. Section 1.2 of the Compliance Section was deleted as duplicative of Section 1.4.

Organization	Yes or No	Question 4 Comment
AEP		While AEP supports, in general, the removal of redundant requirements across standards, we do not yet agree with the proposed changes to TOP-003-2 (for the reasons provided in our response to Question #3). As such, AEP will reserve comment on any future changes that might be made to PRC-001 until further progress is made on TOP-003-2.
Response: Please see response to Q3.		
American transmission Company		ATC agrees with removing R6 from PRC-001, however ATC does not believe it is appropriately addressed in TOP-003-2. If the intent is to have SPS data as a part of a data specification, it should be stated in the requirements of TOP-003-2.
MRO NSRF		The NSRF agrees with removing R6 from PRC-001, however we do not feel it is appropriately addressed in TOP-003-2. If the intent is to have SPS data as a part of a data specification, it should be stated in the requirements of TOP-003-2.
Response: The intent of the data specification requirement concept is that the Transmission Operator and Balancing Authority will request all of the data that they need to fulfill their responsibilities. If that includes SPS data, then they will be expected to request it.		

Organization	Yes or No	Question 4 Comment
No change made.		
Florida Municipal Power Agency		Please see response to Question 6
City of Vero		Please see response to Question 6
Beaches Energy Services of theCity of Jacksonville Beach, Florida		Please see response to Question 6
Response: Please see response to Q6.		
Manitoba Hydro		Section 1.4 Compliance Monitoring and Assessment Processes - Section 1.4 should be removed as it is identical to Section 1.2 'Compliance Monitoring and Reset Time Frame'.
Response: The SDT agrees that the sections are duplicative and has deleted Section 1.2.		
Southwest Power Pool Regional Entity		SPP RE does not believe TOP-003-2 addresses the requirements in PRC-001.
Response: The SDT disagrees. The data specification is required to contain all of the information that a Transmission Operator or Balancing Authority needs to fulfill its obligations. No change made.		
SPP Standards Review Group		No (The Yes/No boxes weren't on the screen. All I got was the comment box.)Deleting the requirements from PRC-001 and including them in R1 and R2 of TOP-003-2 raises the question of what other types of data or information need to be included in the specification that do not normally come to mind when considering this type of information. To be sure that all the bases are covered, we would suggest that the SDT provide a guideline which incorporates the types of data and information they envisioned when drafting these requirements. Additionally, incorporating protective

Organization	Yes or No	Question 4 Comment
		relay information in the data specifications of R1 and R2 raises the potential for auditors to question the contents of an entity's specification. Again, guidance is needed on the part of the TOP and BA in developing the specification initially. Could the SDT provide this initial guidance, or list of examples, in the form of a guideline? Also, measures for R1 and R3 are missing.
Response: The SDT re-iterates its position that the Transmission Operator and Balancing Authority are the best ones to determine the contents of the data specification and that any attempt to provide a minimal list or other guidance would be short-sighted and possibly misleading. The SDT believes that an auditor can only question what is contained in the requirements and in this case that would include only the existence of the data specification and not its contents. Any omissions of data will be caught up in failures to adhere to other standards. No change made. The scope of the changes that the SDT was allowed to make only involved the deletion of the requirements and did not represent a revision of the standard as a whole. That will be taken up in a later project. No change made.		
NV Energy		No, we believe there may be reliability gaps introduced with the specific deletion of old R2 from PRC-001. We are concerned that the open-ended specification of required data per proposed TOP-003 R1 may not adequately cover the notification of status and conditions for certain protection systems and SPS. With the requirement R2 in place, there is no doubt about the need to make notification of these sorts of losses or status changes. Absent the requirement, it is likely that inconsistent specifications for such information by TOP's or BA's will result.
Response: The SDT disagrees. The data specification is required to contain all of the information that a Transmission Operator or Balancing Authority needs to fulfill its obligations. No change made.		
ACES Power Marketing		No. While we are supportive of the changes, they do not appear to be coordinated with the Project 2007-06 System Protection Coordination that was started recently. It appears to retain the retired requirements.
Response: The version of PRC-001 that is posted on the web site is over two years old and does not represent the current work being done with that standard. The SDT has coordinated the changes to PRC-001 with the Project 2007-06 team and the next iteration		

Organization	Yes or No	Question 4 Comment
shown by that project will not have the data requirements. No change made.		
Texas Reliability Entity		No.1) Requirements R2, R5 and R6 of PRC-001-1, which are proposed to be deleted, are not actually replaced by any new or revised requirements in other standards, resulting in reliability gaps. The PRC-001-1 requirements relate to Same-day and Real-time Operations, whereas the TOP-003-2 requirements relate only to the Operations Planning time horizon. The real-time elements of the PRC-001-1 requirements are lost. 2) R2- Removal of R2 assumes that the requirement intent will be included in TOP-003-2 R1 or R2 specification, but there is no new requirement to replace R2 of PRC-001. 3) R2 - The requirements to "take corrective action as soon as possible" are extremely important to the reliability of the system and deleting them introduces a reliability gap. In the Issues Database document there is indication that R5 of TOP-001-2 satisfies the need for corrective action as soon as possible with the following phrase "Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations." However, the text of TOP-001-2 R5 does not actually support this approach and therefore leaves a reliability gap in the Standards. 4) Texas RE disagrees with several of the PRC-001 issues listed as complete in the Issues Database. The referenced TOP Standards are extremely limited in scope and lacking in details (especially in light of ignoring Real-Time issues) and are not considered interchangeable with the deleted PRC-001 Requirements as suggested. 5) R5- Removal of R5 assumes that the requirement intent will be included in TOP-003-2, but there is no new requirement to replace R5 of PRC-001.. R5 is related to the coordination of changes affecting protection systems of others. R5 should not be removed because it deals with coordination issues and not merely specification and provision of data. 6) R6-We object to the proposed removal of R6 because this Real-time requirement is not picked up anywhere else, and elimination of the requirement to monitor and

Organization	Yes or No	Question 4 Comment
		communicate the status of Special Protection Systems will cause a reliability gap. 7) There are no Measures for Requirements R1 and R3.
Response: 1. The SDT disagrees. TOP-003-2 sets up the transfer of Real-time information as shown in Requirements R1 and R2. No change made. 2. The data specification is required to contain all of the information that a Transmission Operator or Balancing Authority needs to fulfill its obligations. No change made. 3. Once the SDT provides notification as per TOP-001-2, Requirement R5, the SDT believes that they will be directed as to what to do. No change made. 4. Without specific comments, the SDT is unable to respond. However, the SDT disagrees that the proposed standards ignore Real-time. No change made. 5. The Transmission Operator already has the responsibility in its core set of duties to provide such coordination and the SDT believes that a separate requirement is not needed to reinforce this. No change made. 6. The SDT disagrees. The data specification is required to contain all of the information that a Transmission Operator or Balancing Authority needs to fulfill its obligations. No change made. 7. The scope of the changes that the SDT was allowed to make only involved the deletion of the requirements and did not represent a revision of the standard as a whole. That will be taken up in a later project. No change made.		
NextEra Energy, Inc.		Yes, we agree.
Liberty Electric Power LLC		Yes. Thank you to the SDT for removing these requirements.
Bonneville Power Administration		Yes, BPA is in support of the retirement of the three requirements in PRC-001 as the SDT is suggesting.
Essential Power, LLC		Yes, I support the recommendation.
Arizona Public Service		Yes, we agree with the changes the drafting team has made.

Organization	Yes or No	Question 4 Comment
Company		
Southern Company		Yes, we agree with the SDT's suggestion
City of Austin dba Austin Energy		We agree.
Imperial Irrigation District (IID)		Yes
Duke Energy		Yes
MidAmerican Energy		Yes - retire the three requiements in PRC-001
Cowlitz County PUD		Cowlitz supports the retirement.
FirstEnergy Corp		FE agrees with the changes that have been made by the drafting team.
Ingleside Cogeneration LP		Ingleside Cogeneration LP agrees that relay and equipment status can be included in a telemetry specification as part of TOP-003-2 - which is redundant with PRC-001-1 R2 and R6. Similarly, the coordination of changes in generation operating conditions such as de-ratings that could require changes in the TOP's Protection System (R5) can be captured in existing data submission vehicles that TOP-003-2 will also cover.
Oncor Electric Delivery		Agree with changes
Dominion		Agree with changes made.
Response: Thank you for your support.		

5. **The VRF, VSL, and Time Horizons are part of a non-binding poll. Please indicate whether you agree or disagree with the VRF, VSL, and Time Horizon assignments. If you do not support these assignments or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Several typos in the VRF/VSL justification document were pointed out by commenters and have been fixed. No other changes have been made to the VRFs or VSLs.

Organization	Yes or No	Question 5 Comment
PNGC Group Comments	No	Please see our response to Question 2.
Response: Please see response to Q2.		
AEP	No	In general, the VRFs and VSLs are too severe and punitive. Those stated for R1, R2, and R5 of TOP-001-2 are especially so, given what we see as open-endedness to what might be requested. As a result, AEP cannot support the proposed VRFs and VSLs.
Response: The SDT believes that the VRFs and VSLs follow accepted guidelines. Without any specific comments, the SDT is unable to provide specific responses. No change made.		
ACES Power Marketing	No	The Moderate and High VSLs for TOP-001-2 R3, R5, R6, and R8 incorrectly use an "or" condition when "and" is necessary to establish the range of percentages of performance. As written now, any percentage from 0 to 100% qualifies for both VSLs. The following boiler plate language that is written before the VSLs for TOP-001-2 R8 needs to be included before all sets of VSLS that give an option to use integers or percentages. Otherwise, the VSLs will overlap. It should be included before TOP-001-2 R3, R5, and R6. "For the Requirement X VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this

Organization	Yes or No	Question 5 Comment
		manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.“ For the Severe VSL of TOP-002-3 R3, an extra space is needed before “15%”.
Response: The SDT agrees and has made conforming changes. The second ‘or’ condition in the Moderate and High VSLs is now “and”. The boilerplate language cited is merely an explanation of the SDT’s intent. The standard has been modified to show this language for Requirements R3, R5, R6, and R8 as suggested. The SDT agrees and has corrected the typo.		
MidAmerican Energy	No	See the NSRF comments
MRO NSRF	No	TOP-001-2 The adding the language of “or 5% or less of the affected Transmission Operators, whichever is less”, “or more than 5% or less than or equal to 10% of the affected Transmission Operators, whichever is less”, “or more then 10% or less than or equal to 15% of the affected Transmission Operators, whichever is less”, “ or more than 15% of the affected Transmission Operators, whichever is less” to R3, R5, and R6 is confusing and not necessary. For example: 10 affected TOs. The lower VSL states: The TO did not inform one other TO or 5% or less of the affected TOs, whichever is less. 5% of 10 is .5 TOs which is less than 1. The percentage language should be removed. TOP-003-2 - Same issue with VSLs as with TOP-001-2. The percentage language should be removed from R3 and R4. PRC-001-2 - R1 VSL for High and Severe seem arbitrary. Not knowing limitations are not as bad as not knowing purpose? Suggest either breakdown by number of systems. Ie: did not know purpose and limitations of 1 protection scheme, etc. Or Binary. Severe - did not know purpose and limitation of protections systems in its area.
Response: The percentage language was added at the direct behest of the Quality Review Team and utilizes standard language for		

Organization	Yes or No	Question 5 Comment
this type of situation. No change made.		
Luminant	No	The VSL for TOP-003-2 R5 places a more stringent severity level on the entities receiving the data requests than it places on the entities that are responsible for creating the data requests. As such, I would suggest changing the VSL for TOP-003-2 R5 to the following:Lower: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy one of the obligations of the documented specification for data Moderate: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy two of the obligations of the documented specification for data High: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy three of the obligations of the documented specification for data Severe: The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy four or more of the obligations of the documented specifications for data.
Response: The SDT sees the previous requirements in TOP-003-2 as ahead of time requirements which mean that there is some slack that can be incorporated into the deliberations without jeopardizing reliability and VSLs reflect this fact. However, Requirement R5 is about the actual data transfer and there is no room for error, thus the more stringent VSL. No change made.		
Kansas City Power & Light	No	In addition, the VSL for R5 in TOP-003 does not reflect partial efforts to exchange data by Entities.
Response: Requirement R5 is about the actual data transfer and there is no room for error, thus the more stringent VSL. No change made.		
Liberty Electric Power LLC	No	As written data transmission failures subject REs to a severe violation in R5, see Q3 response.
Response: Please see response to Q3.		
NV Energy	No	PRC-001 R1: Though this requirement does not appear to be within the scope of the

Organization	Yes or No	Question 5 Comment
		SDT's efforts in this project, we note that for R1 (familiarity of purpose and limitations of protection systems), there is no Measure in the Standard, and the VSL's appear to be quite subjective. I would like to make a specific suggestion, but cannot do so without knowing what sort of Measures are intended for this requirement. Perhaps, change the VSL language to state "Entity does not possess documentation describing purpose/limitations of its protection systems for its Operator personnel."
Response: The scope of the changes that the SDT was allowed to make only involved the deletion of the requirements and did not represent a revision of the standard as a whole. That will be taken up in a later project. No change made.		
Duke Energy	No	o TOP-001-2 VSLs should be revised consistent with our comments on the requirements. o TOP-003-2 VSLs have explanatory language on how the SDT intends the VSLs to be used. This language needs to be incorporated into the VSLs more directly, because compliance personnel will not be bound by the SDT's intent.
Response: No changes were made to the requirements as explained in Q1. No change made. The SDT believes that the VSL language is correct and will not need to be changed to reflect the explanation which will be deleted from the final draft. It was provided here for ease of reference to commenters. No change made.		
Texas Reliability Entity	No	1) VSL for TOP-001-2 R3: Operational Planning Analysis, by definition, excludes Real-Time issues such as "actual Emergencies." We suggest improving the requirement as discussed above and then making conforming revisions to this VSL. 2) VSL for TOP-001-2 R5: "When conditions permit" is subjective and ambiguous therefore consistency in auditing will not occur. Are you sure that "whichever is less" is what you mean to say here? (also applies to VSLs for R3, R6 and R8) 3) TOP-001-2 R7: VRF justification statement is incomplete ("The requirements are viewed as similar since they both refer to <missing text>") 4) TOP-001-2 R8: In the VRF justification, the text in the second and third bullets

Organization	Yes or No	Question 5 Comment
		appears to be garbled. 5) TOP-001-2 R9: We recommend this requirement be assigned a "High" VRF. Uncorrected SOL violations could cause bulk power system instability, separation, and or cascading if exacerbated in Real-Time by other SOL violations, contingencies, faults, or misoperations (and may be dependent on the SOL Methodology timing in FAC-011 and not be captured in TOP-001-2 R7). Note that the VRF justification for R10 correctly refers to a High VRF for R9. Additionally, remove the word "local" in all places used in the R9 VRF justification.
Response: 1. No changes were made to the requirement as explained in Q1. Therefore, no changes are necessary to the VSL. **2.** The SDT reviewed the indicated wording and verified that it is what was meant. As conditions permit is well accepted terminology in a situation where a hard and fast value is not possible. No change made. **3.** The SDT agrees and has corrected the text. **4.** The SDT agrees and has corrected the text. **5.** SOLs, by definition, can't cause instability, etc., and thus the VRF is correctly stated as Medium. The VRF justification document will be corrected accordingly. The SDT believes that the use of 'local' is appropriate.		
Oncor Electric Delivery	No	For TPL-001"Oncor respectfully takes the position that the proposed language in R6 will not provide a coordinated communication effort in the event of a planned outage of telemetry, control equipment and associated communication channels. The term "negatively impacted interconnected registered entities" is too broad and too subjective. Oncor believes that the Reliability Coordinator is in the best position to determine who is negatively impacted and that they should be the entity that makes further notification after receiving the initial planned outage request from the originating entity."
Response: Please see response to Q1.		
Cowlitz County PUD	No	After reviewing the industry comments submitted, Cowlitz is respectfully perplexed

Organization	Yes or No	Question 5 Comment
		why comments were not addressed related to the VSL binary treatment of R5. A data specification document may be very complex, and the Standard does not define non-compliance other than obligations were not satisfied. One data variable missing (either accidental omission or inability to provide) can incur an immediate violation if the data specification document does not include any leniency in this regard. Further, the proposed VLS for R5 does not allow for any credit of the entity's effort in fulfilling the obligations set forth in a data specification document.
Response: The SDT disagrees. Requirement R5 is not about individual failures in communications. Please see response to Q3. No change made.		
Bonneville Power Administration		TOP-001-2 VRFs/VSLs - NO - BPA recommends a sliding scale based on duration and percentage of the SOL violation. Example: If an entity is high by 2% of the SOL for 1 minute, their VSL should be substantially lower than if they were 25% off for more than 30 minutes. Sliding scale should start at the bottom ... couple of MW for a minute ... as an example. TOP-002-3: VRFs/VSLs - NO - BPA recommends a sliding scale based on how far off the original study was from the after the fact analysis. Example: If an entity did not have a study, the penalty should be severe. If an entity did have a study, but it was only 5% off, the penalty should be less severe. TOP-003-2 VRFs/VSLs - YES - BPA is in support.
Response: The SDT understands the concept of a sliding scale that is being suggested but finds it impractical and potentially unwieldy to implement. In addition, it doesn't take into account the fact that 2% on one line in a particular location may be a more severe impact on the overall reliability of the system than 25% on another line. No change made.		
Western Eledtricity Coordinating Council	Yes	I support the language of the VSLs for the proposed standards. I also understand the logic behind the statement included above the VSLs for R8 of TOP-001 and R3 and R4 of TOP-003. However, I question whether or not it is appropriate for this type of language to appear in the VSLs. It seems that this should be handled by the Regional

Organization	Yes or No	Question 5 Comment
		Enforcement departments.
Response: That language will be removed in the final draft. No change made.		
Independent Electricity System Operator	Yes	In the Violation Severity Levels section of the standards, items that contain "whichever is less" following the "or" statement, may be difficult to interpret.As a suggestion, this could be addressed by improving the wording, providing examples or categorizing non-compliance as a percentage only (rather than a number "or" percentage, whichever is less)
Response: The percentage language was added at the direct behest of the Quality Review Team and utilizes standard language for this type of situation. No change made.		
City of Austin dba Austin Energy	Yes	The VSL for TOP-001-2, R8 includes instruction to "start with the Severe VSL first and then to work your way to the left until you find the situation that fits." It explains that the goal is to assign a Severe VSL to a small entity who has just one affected reliability entity to inform and fails to do so. This structure usually makes sense; however, it is not applicable to R8. R8 requires the TOP to inform its RC of SOLs that have been identified as supporting reliability. The variability in the requirement is in the number of SOLs identified not in the number of registered entities to inform. The intent of being non-discriminatory by size of entity is already covered with regards to the number of SOLs identified because the VSL uses the "# SOLs or % of SOLs, whichever is less" approach, and the instruction becomes unnecessary. Austin Energy recommends that the SDT remove the instruction statement above R8.
Response: The statement will be removed in the final draft. No change made.		
Imperial Irrigation District (IID)	Yes	
Dominion	Yes	

Organization	Yes or No	Question 5 Comment
SPP Standards Review Group	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
Idaho Power Company	Yes	
Ingleside Cogeneration LP	Yes	
Manitoba Hydro	Yes	
FirstEnergy Corp	Yes	
NextEra Energy, Inc.	Yes	
Response: Thank you for your support.		

6. **If you have any other comments on these standards that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: The SDT identified one comment on the mapping document that was corrected due to comments received to this question.

Organization	Yes or No	Question 6 Comment
AEP Marketing, AEP Service Corp.	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
American Electric Power	Negative	Comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Cowlitz County PUD	Negative	Comment submitted.
Duke Energy, Duke Energy Carolina	Negative	Comments submitted.
Florida Municipal Power Agency	Negative	Please see FMPA comments submitted separately.
Kansas City Power & Light Co.	Negative	Comments and concerns with the proposed standards have been expressed within the NERC comment form.
Lakeland Electric	Negative	"Please see FMPA comments submitted separately"
Luminant Energy	Negative	See comments submitted by Luminant.

Luminant Generation Company LLC	Negative	Comments submitted via NERC web comment form.
Omaha Public Power District	Negative	Please see OPPD comments from Doug Peterchuck
Progress Energy Carolinas	Negative	Comments submitted
Response: Thank you for submitting comments.		
City of Green Cove Springs	Negative	The existing TOP-001-1 R7 essentially requires communication to the RC and neighboring TOPs any time a Facility is to be switched. The new TOP-001-2 R5 will only require such communication when such switching would result in an "Adverse Reliability Impact" defined as: "The impact of an event that results in frequency-related instability; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection." This significantly reduces the requirements for communication / notification for switching Facilities. It is worthwhile to communicate switching of some Facilities whether or not they would result in an "Adverse Reliability Impact". Suggest rephrasing to something like any unplanned switching of Facilities not "noticed" through data provision of TOP-003-2. With the number of human error events that have occurred, we should not be reducing the communication / notification requirements. R8 is not needed since it is already covered in FAC-014-2 R5.2. As a result, R9, R10 and R11 ought to be modified to refer to FAC-014-2 rather than R8.
Response: R7: The SDT believes that notification for any switching event is contrary to good operating practice as it would load up the message queue with unnecessary information and could lead to an operator missing an important message within a group of unneeded messages. TOP-003-2 allows for an entity to request reliability-based information from another entity so they may include status on any piece of equipment that may possibly effect its operations. Therefore, the SDT does not believe that a reliability gap has been created. No change made. R8: The SDT asserts that there are subtle differences in TOP-001-2 and FAC-014-2 that the commenter is missing. FAC-014-2 provides a simple list of SOLs while TOP-001-2 is looking at particular SOLs that need special treatment. Therefore, there is no redundancy. No change made.		

City of Green Cove Springs	Negative	The existing TOP-002-2 requires that both the BA and TOP perform current day, next day and seasonal plans. In the new TOP-002-3, the BA is eliminated from the applicability. Nowhere else in the standards is there a requirement for the BA to perform current-day, next-day and seasonal planning. The mapping document points to BAL-002 and the requirement for a BA to have enough Contingency Reserves (and confuses the references saying the R2 of BAL-002-1 requires a "plan", which it does not say). However, this is a real-time requirement of a BA and is not an operations planning analysis and is not a day-ahead plan. There ought to be a day-ahead plan to start enough generation to enable the load plus operating reserves to be met, which the existing TOP-02-2 standard essentially assigns to the BA. The mapping document also points to BAL-001, but, a 12-month rolling average of ACE has very little to do with day-ahead planning. And finally, the mapping document points to coordination needed in the Functional Model. The Functional Model is not mandatory and should not be depended upon in this manner. The mapping document says that the TOP develops the plan and passes it to the BA. This is not the case for unit commitment. For unit commitment, it is usually the other way around. TOPs develop constraints (e.g., SOLs) that the market participants use to transact; hence, the market participants (which involve the BAs) develop the transactions (which include unit commitment) often in parallel with the TOPs plans. TOPs do not plan or direct unit commitment except in cases where a unit needs to be "reliability must-run". We are aware that there may be efforts to insert next-day planning into new BAL standards under development; however, it will be some time before those new standards are approved. IN the meantime, the new TOP standards should include operational planning analyses for the BA on an interim basis until those new BA standard(s) are approved and mandatory so that we do not create a gap in the interim. In addition, the standard has eliminated the current-day day and seasonal assessments and focuses only on next-day. we believes that both current-day and seasonal remain important, to cover changes from yesterday’s plan (e.g., unplanned outages that have occurred since yesterday’s plan), and to coordinate planned outages seasonally.

Response: The Balancing Authority has one role - to balance Load and resources. A key component of this role is to be able to recover from events that cause imbalance. The commenter intermingles the obligation of the Load-Serving Entity with that of the Balancing Authority. The SDT believes that in order for a Balancing Authority to comply with CPS and DCS and the requirements for emergency plans in EOP standards that they must plan and therefore a separate requirement is not needed and would actually represent double jeopardy. BAL-001-0.1a, BAL-002-1, EOP-001-0b, EOP-002-3, and EOP-003-1 cover these issues for the Balancing Authority. The standard has not eliminated other planning periods as Operational Planning Analysis covers all of the periods cited. What it does do is mandate a next-day analysis. Current day will be handled in Real-time operations and thus isn't needed in this planning environment. The SDT believes that longer term studies will be run by entities on an as needed basis but that requirements are only necessary for next-day. No change made.		
City of Green Cove Springs	Negative	R1 - The SDT introduces a new term "Stability Limit" which seems duplicative of an SOL and adds a layer of ambiguity. What Stability Limits exist that would not be an SOL or IROL? Also, R1 and R2 become inconsistent with R1 referring to "Facility Ratings" and "Stability Limits" whereas R2 refers to "SOLs" and "IROLs". It would seem the two requirements should consistently use "SOLs" and "IROLs" consistently with FAC-014-2. Related to the BA performing a day-ahead plan discussed in FMPA's response to question 2, TOP-003-2 R2 only requires a BA to develop data specifications for reporting in real-time (i.e., bullet 2.1). There should be requirements for day-ahead as well. There are a number of data requirements that are proposed to be deleted and replaced with an ambiguous reference to a "specification for the data necessary", or a data specification, without any minimal requirements for what should be in that data specification. This approach will likely not go over well with the regulators. The SDT should be able to define a minimal list of data required, e.g, "such data specification will at minimum include: next-day load forecasts, next-day planned outages, generator capacity changes, protection system failures, special protection system status, real-time monitoring of generation and transmission, transmission Facility status, etc., etc." (note that these are all examples of specific requirements within the existing standards that the SDT is proposing to delete), possibly as an attachment to the standard.

Response: Stability Limit is a defined term in the NERC Glossary. IROLs and SOLs represent only part of what the Operational Planning Analysis (OPA) is to include. The OPA is to analyze all expected system conditions against all operating criteria. The SDT finds that is accomplished within a Transmission Operator Area by having an OPA that is assessed not to exceed any of its Facility Ratings or Stability Limits. While IROLs and SOLs represent many of these, they may not be granular enough to represent all of them. No change made. The SDT agrees and has made conforming changes to Requirement R2, Part2.1. **Part 2.1**. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring. The data specification concept has already been approved by FERC for Reliability Coordinators in the IRO standards. No change made.		
City of Green Cove Springs	Negative	While we agrees with a results-based approach to standards, it seems to us that there have been a number of human-error based problems that justify agreed upon protocols and procedures being covered by the standards. Hence, TOP-004 R6, which requires development of formal policies and procedures among neighboring TOPs should not be eliminated from the standards. On the Mapping Document, TOP-004-2 R5, on the discussion that the requirement be deleted, the document says that the TOP does not have the authority to unilaterally separate without the approval of the RC. FMPA believes that they do if there is an imminent threat (e.g., the exceptions to IRO-001-2 of “unless such actions would violate safety, equipment, or regulatory or statutory requirements”). So, while FMPA agrees that the requirement can be deleted, the reason for the deletion does not seem accurate.
Response: TOP-004-2, Requirement R6 has been superseded by the NERC Reliability Standards taken as a whole. Examples of such would be the proposed TOP-001-2. The SDT agrees and has updated the mapping document accordingly.		
City of Garland	Negative	R5 VSL levels should have low, moderate, and high - not just severe

Response: As explained in Q5, there is no room for error in Requirement R5 and thus it has been assigned a binary VSL. No change made.		
Commonwealth of Massachusetts Department of Public Utilities	Negative	o There is use of the term "Reliability Directive" in the standard which is currently and formally under development as part of another project. The posting states that this definition was agreed to by all affected project teams using it, however if the other project team formally charged with this definition's development, changes it, then this standard and perhaps others, will have to be revisited. Bringing these standards forward seems inefficient and problematic for many. o Also in Requirement 8 there was an issue expressed by one RSC member that System Operating Limits are local limits and should not be subject of part of the NERC standards and the requirement as written creates a "subset" of SOLs that affect reliability. This could create an overly complicated standard and could lead to compliance difficulties.
Response: Please see response to identical comments in Q1.		
Detroit Edison Company	Negative	R3- The sentence should read "... inform its Reliability Coordinator and other Transmission Operator(s), ..." The word other is missing in the current draft. R6- The statement "... negatively impacted interconnected NERC registered entities..." is to vague. This could be an easy trip up during an audit. M6- same as R6- The statement "... negatively impacted interconnected NERC registered entities..." is to vague. VSLs- R6- The statement "... negatively impacted interconnected NERC registered entities..." is to vague.
Response: Please see response to identical comments in Q1.		

East Kentucky Power Coop.	Negative	The standard as proposed does not appear to comply with the stated intent of Project 2007-03, that being: "The industry needs clearer, unambiguous and enforceable standards in order to effectively operate the Bulk Electric System." Not only are the changes to TOP-003 as vague-or ambiguous--if not more so than the previous TOP-003-1 standard, the requirements do not provide for any consistency between companies. For example, who between two parties determines, or in the case of an inability to reach agreement, who is responsible for arbitrating an agreement when two neighboring entities are attempting to establish a "mutually agreeable format". Resolution could be problematic when required changes to a format between entities A and B would require format changes between entities A and C, A and D, and A and E, and would potentially require entity A to maintain several different format standards to meet the requirements for coordination between entities B, C, D, and E. Many items previously in TOP-003-1 appear to have been completely abandoned in lieu of much less prescriptive specifications in TOP-003-2. For example, clear provisions regarding timing of data availability listed in TOP-003-1 are not specified in any form in TOP-003-2 other than to require that entities needing to share data essentially "work it out amongst themselves". The standard needs to better guide entities in regard to the type of data-at a minimum-they SHOULD be requesting and obtaining. Alternately, such format specifications should be left to the authority of the RC to coordinate among TO/BA entities for which they are responsible.
Response: Please see response to identical comment in Q3.		
INTELLIBIND	Negative	There should either be a description of what the specific vote is for, or a link to the information for each vote if you want to encourage affirmative voting.
Response: Your comment will be passed on to staff for consideration in future postings.		
National Association of Regulatory Utility Commissioners	Negative	Given the standard uses the term Reliability Directive as a defined term but is not proposing to define the term in this standard for adoption in the glossary, it is inappropriate to finalize this standard.

Response: Please see response to Q1.		
Oncor Electric Delivery	Negative	Oncor believes that the Reliability Coordinator is in the best position to determine who the negatively impacted interconnected registered entities are and to effectively coordinate communication efforts after receiving the initial planned outage request from the originating entity. In addition, the term “negatively impacted interconnected registered entities” is too broad and too subjective. As a result, we recommend R6 be revised to: Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
Response: Please see response to identical comment in Q1.		
ReliabilityFirst Corporation	Negative	ReliabilityFirst votes in the negative and offers the same comments as submitted via the previous comment posting period.
Response: Without specific comments, the SDT is unable to respond other than to point to previous posting responses.		
Santee Cooper	Negative	The implementation date should be at least twelve months to be consistent with TOP-001-2 and TOP-002-3. What was the rationale of reducing the implementation time from twenty-four months to ten months?
Response: The implementation date was reduced due to multiple comments in the previous posting as commenters felt that the proposed standards reflected what was already being done and would not incorporate much change. The ten month implementation period was intended to allow time for dissemination of the data specification prior to the other changes taking effect (the standards with a 12 month implementation period.)		

Seattle City Light	Negative	While the idea of making each BA and TOP formally outline a data specification for all the information it needs to perform its Operational Planning Analysis is a worthy concept, the requirements in this Standard for evidence and data retention are onerous. Specifically the requirement to retain all electronic or hard copies of data transmittals or retain attestations from all receiving entities would require a tremendous amount of resources to be compliant. It may also be technically impossible to comply with these requirements because the data specifications developed individually by each entity may not be compatible with each other. The formats and periodicity of data collected by each entity may not be compatible with the specifications and it could be impossible to comply with these requests without major changes to the infrastructure. As an alternative, most of the NERC registered entities are currently required to provide that data to their Reliability Coordinators (RC) using the specifications already developed by the RCs and that data could be used by the TOPs and BAs to perform their functions. Seattle City Light supports the efforts of the Real Time Operations Standards Drafting Team and approves of the direction proposed in these new TOP Standards. We are prepared to vote “affirmative” once details as discussed above are addressed and resolved.
Response: Please see response to identical comment in Q3.		
Southwest Transmission Cooperative, Inc.	Negative	The Moderate and High VSLs for TOP- 001-2 R3, R5, R6, and R8 incorrectly use an “or” condition when “and” is necessary to establish the range of percentages of performance. As written now, any percentage from 0 to 100% qualifies for both VSLs “For the Requirement X VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.” For the Severe VSL of TOP-002-3 R3, an extra space is needed before “15%”.
Response: Please see response to identical comment in Q5.		

Western Electricity Coordinating Council	Abstain	I agree with the language of the VSLs for TOP-003-2. I also understand the logic behind the statement included above the VSLs for R3 and R4. However, I question whether or not it is appropriate for this type of language to appear in the VSLs. Is seems that this should be handled by the Regional Enforcement departements.
Response: The language will be removed from the final drafts. No change made.		
Mississippi Power	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Gulf Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Georgia Power Company	Affirmative	See comments submitted by Antonio Grayson.
Bonneville Power Administration	Affirmative	Please see BPA's submitted comments
Alabama Power Company	Affirmative	See comments submitted via the electronic comments form by Antonio Grayson.
Southern Company Generation	Affirmative	Please see comments submitted by Antonio Grayson on behalf of each part of Southern Company.
Response: Thank you for submitting comments.		
Nebraska Public Power District	Affirmative	NPPD joins comments submitted by the Southwest Power Pool (SPP).

Southwest Power Pool, Inc.	Affirmative	We continue to disagree with the successive ballot process that forces entities to decide on a voting position concurrent with the submittal of comments on the same. NERC needs to explore other ways to expedite the voting/comment process without forcing industry to have faith that changes will be made after approval. Although SPP votes in favor of this standard, we have outstanding comments that should be addressed. We have submittted them in the standards processs and reiterate some of them here. The Purpose Statement is too general and does not provide any direction of how the proposed standard will meet its stated intent. As written the Purpose Statement is applicable to any NERC standard that exists or can be imagined. We suggest additional wording of how this particular standard intends to do what it intends to is needed. For example, "...by requiring applicable entities to have the data necessary to perform reliability analyses and real-time monitoring.'
Response: Please see response to identical comment in previous questions.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	If a Transmission Operator or a Balancing Authority is requesting data from another entity, they must demonstrate a reliability impact validating the need for the requested data.
Response: Please see response to identical comment in Q3.		
City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative	We would like to request that specific definitions are included for the individual time horizons. We suggest the following potential definitions: 1. Same Day Operations - Routine actions required within the time frame of a day, but not real-time. 2. Real-time Operations - Actions required within one hour or less to preserve the reliability of the bulk electric system. 3. Operations Assessment - Follow-up evaluations and reporting of real-time operations.
Response: The latest set of approved Time Horizon classifications is posted on the Reliability Standards Resources Web Page.		
Electric Reliability Council of Texas, Inc.	Affirmative	ERCOT supports the SDT's modifications.

Response: Thank you for your support.

END OF REPORT

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.
11. Sixth posting of revised standard on December 14, 2011.
12. Seventh posting of revised standard on March 22, 2012.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that 3 requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated on a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

A. Introduction

1. **Title:** **Transmission Operations**

2. **Number:** TOP-001-2

3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.

4. **Applicability**

   4.1. Balancing Authority

   4.2. Transmission Operator

   4.3. Generator Operator

   4.4. Distribution Provider

   4.5. Load-Serving Entity

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities..

B. Requirements

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning,]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence that it complied with each Reliability Directive issued and identified as such by the Transmission Operator(s) unless such action would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M2. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified, Reliability Directive(s) issued in accordance with Requirement R2. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M3. Each Transmission Operator shall make available, upon request, evidence that it has informed its Reliability Coordinator and Transmission Operators that it knew or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M4. Each Transmission Operator shall make available, upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4, unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M5. Each Transmission Operator shall make available, upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5, unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M6. Each Balancing Authority and Transmission Operator shall make available, upon request, evidence that it notified its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Balancing Authority or Transmission Operator may provide an attestation that an event has not occurred.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include, but is not limited to, an electronic or hard copy of information from the Operational Planning Analysis used in its assessment, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration that would cause a violation of the Facility

Rating or Stability criteria upon which it is based, as specified in Requirement R8 and in Requirement R9. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8, in accordance with Requirement R11. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year,

with the exception of voice recordings which shall be retained for a minimum of 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, and such action would not have violated safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
For the Requirement R3, R5, R6, and R8 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting

	Lower	Moderate	High	Severe
				entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R5	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% and less than or equal to 10% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% and less than or equal to 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform its Reliability Coordinator of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
R6	The responsible entity did not notify one negatively-impacted interconnected NERC-registered entity, or 5% or less of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively-impacted interconnected NERC-registered entities, or more than 5% and less than or equal to 10% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify three negatively-impacted interconnected NERC-registered entities, or more than 10% and less than or equal to 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more negatively-impacted interconnected NERC-registered entities, or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and

	Lower	Moderate	High	Severe
				control equipment and associated communication channels between the affected entities.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs, or more than 5% and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs, or more than 10% and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs, or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL), as identified in Requirement R8, for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, had been exceeded.
R11	N/A	N/A	N/A	The Transmission Operator did not act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's

	Lower	Moderate	High	Severe
				$T_{v,}$ or of an SOL identified in Requirement R8.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.
11. Sixth posting of revised standard on December 14, 2011.
12. Seventh posting of revised standard on March 22, 2012.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that 3 requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	~~3~~2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

Three separate drafting teams wrote definitions for Reliability Directive. The three drafting teams have coordinated on a common definition and agreed that the Reliability Coordinator Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference although it needs to be noted that this is still a draft and hasn't been approved by the industry.

Reliability Directive — A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

A. Introduction

1. **Title:** **Transmission Operations**
2. **Number:** TOP-001-2
3. **Purpose:** To prevent instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences.
4. **Applicability**
   - **4.1.** Balancing Authority
   - **4.2.** Transmission Operator
   - **4.3.** Generator Operator
   - **4.4.** Distribution Provider
   - **4.5.** Load-Serving Entity
5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities..

B. Requirements

R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each Reliability Directive issued and identified as such by its Transmission Operator(s), unless such action would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: ~~Operations Planning,~~ Same-day Operations, Real-Time Operations]*

R2. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator. *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same Day Operations, Real-time Operations]*

R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operator(s) that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. *[Violation Risk Factor: High] [Time Horizon: Operations Planning,]*

R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Examples of such operations are relay or equipment failures, and changes in generation, Transmission, or Load. *[Violation Risk Factor: High] [Time Horizon: Same-day Operations, Real-Time Operations]*

R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale: The class of SOL included in Requirements R8, R9, and R11 was created in response to industry comments that there were SOLs that deserved increased attention. Examples of such SOLs include WECC Path SOLs, SOLs on transmission facilities maintaining service to significant events or buildings, such as the stadium for major nationally televised events, prominent government buildings, and military installations.

R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. *[Violation Risk Factor: Medium] [Time Horizon: Real-Time Operations]*

R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

C. Measures

M1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence that it complied with each Reliability Directive issued and identified as such by the Transmission Operator(s) unless such action would violate safety, equipment, regulatory, or statutory requirements, in accordance with Requirement R1. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M2. Each Balancing Authority, Generation Operator, Distribution Provider, and Load-Serving Entity shall make available, upon request, evidence which may include, but is not limited to dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence in electronic or hard copy format, that it informed its Transmission Operator of its inability to comply with identified, Reliability Directive(s) issued in accordance with Requirement R2. If no event has occurred, the Balancing Authority, Generator Operator, Distribution Provider, or Load-Serving Entity may provide an attestation that an event has not occurred.

M3. Each Transmission Operator shall make available, upon request, evidence that it has informed its Reliability Coordinator and Transmission Operators that it knew or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis in accordance with Requirement R3. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M4. Each Transmission Operator shall make available, upon request, evidence that requested and available emergency assistance was rendered to other Transmission Operators in accordance with Requirement R4, unless such actions would violate safety, equipment, regulatory, or statutory requirements. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence in electronic or hard copy format. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M5. Each Transmission Operator shall make available, upon request, evidence that it informed its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas in accordance with Requirement R5, unless conditions did not permit such communications. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M6. Each Balancing Authority and Transmission Operator shall make available, upon request, evidence that it notified its Reliability Coordinator and negatively impacted interconnected NERC registered entities of planned outages of telemetering equipment, control equipment, and associated communication channels in accordance with Requirement R6. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence. If no event has occurred, the Balancing Authority or Transmission Operator may provide an attestation that an event has not occurred.

M7. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v as specified in Requirement R7. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M8. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis in accordance with Requirement R8. Such evidence could include, but is not limited to, an electronic or hard copy of information from the Operational Planning Analysis used in its assessment, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M9. Each Transmission Operator shall make available evidence for any occasion in which it has operated outside an SOL for a continuous duration that would cause a violation of the Facility

Rating or Stability criteria upon which it is based, as specified in Requirement R8 and in Requirement R9. Such evidence could include, but is not limited to, dated computer logs or reports in electronic or hard copy format specifying the date, time, duration, and details of the excursion. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M10. Each Transmission Operator shall make available evidence that it has informed its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded in accordance with Requirement R10. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

M11. Each Transmission Operator shall make available evidence of when it acted or directed others to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8, in accordance with Requirement R11. Such evidence could include, but is not limited to, dated operator logs, voice recordings or transcripts of voice recordings, or dated computer printouts. If no event has occurred, the Transmission Operator may provide an attestation that an event has not occurred.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

Exception Reporting

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, and Load-Serving Entity shall each keep data or evidence for each applicable Requirement R1 through R6, R8, and R10 through R11 and Measure M1 through M6, M8, and M10 through M11 for the current calendar year and one previous calendar year,

with the exception of voice recordings which shall be retained for a minimum of ~~ninety~~ 90 calendar days, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

Each Transmission Operator shall retain evidence for three calendar years of any occasion in which it has exceeded an identified IROL and its associated IROL T_v or SOL identified in Requirement R8 as specified in Requirements R7 and R9 and Measurements M7 and M9.

If a Balancing Authority, Transmission Operator, Generator Operator, Distribution Provider, or Load-Serving Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not comply with an identified Reliability Directive issued by the Transmission Operator, and such action would not have violated safety, equipment, regulatory, or statutory requirements.
R2	N/A	N/A	N/A	The responsible entity did not inform its Transmission Operator of its inability to perform an identified Reliability Directive issued by that Transmission Operator.
For the Requirement R3, R5, R6, and R8 VSLs only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% ~~or~~and less than or equal to 10% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% ~~or~~and less than or equal to 15% of the affected Transmission Operators, whichever is less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.	The Transmission Operator did not inform its Reliability Coordinator of an actual Emergency or an anticipated Emergency condition based on its assessment of its Operational Planning Analysis. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is ~~less, that~~less, that are known or expected to be affected by an actual or anticipated Emergency based on its assessment of its Operational Planning Analysis.
R4	N/A	N/A	N/A	The Transmission Operator did not render emergency assistance to other Transmission Operators, as requested and available, when the requesting

	Lower	Moderate	High	Severe
				entity had implemented its comparable emergency procedures, and such actions would not have violated safety, equipment, regulatory, or statutory requirements.
R5	The Transmission Operator did not inform one other Transmission Operator, or 5% or less of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform two other Transmission Operators, or more than 5% ~~or~~and less than or equal to 10% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform three other Transmission Operators, or more than 10% ~~or~~and less than or equal to 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on respective Transmission Operator Areas when conditions did permit such communications.	The Transmission Operator did not inform its Reliability Coordinator of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications. OR The Transmission Operator did not inform four or more other Transmission Operators, or more than 15% of the affected Transmission Operators, whichever is less, of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas when conditions did permit such communications.
R6	The responsible entity did not notify one negatively-impacted interconnected NERC-registered entity, or 5% or less of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify two negatively-impacted interconnected NERC-registered entities, or more than 5% ~~or~~and less than or equal to 10% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment, and associated communication channels between the affected entities.	The responsible entity did not notify three negatively-impacted interconnected NERC-registered entities, or more than 10% ~~or~~and less than or equal to 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering equipment, control equipment and associated communication channels between the affected entities.	The responsible entity did not notify its Reliability Coordinator of a planned outage of telemetering equipment, control equipment, and associated communication channels. OR, The responsible entity did not notify four or more negatively-impacted interconnected NERC-registered entities, or more than 15% of the negatively impacted NERC registered entities, whichever is less, of a planned outage of telemetering and

	Lower	Moderate	High	Severe
				control equipment and associated communication channels between the affected entities.
R7	N/A	N/A	N/A	The Transmission Operator exceeded an identified Interconnection Reliability Operating Limit (IROL) for a continuous duration greater than its associated IROL T_v.
~~For the Requirement R8 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.~~				
R8	The Transmission Operator did not inform its Reliability Coordinator of one SOL, or 5% or less of the SOLs, whichever is less, which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of two SOLs, or more than 5% ~~or~~and less than or equal to 10% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of three SOLs, or more than 10% ~~or~~and less than or equal to 15% of the Sols whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**	The Transmission Operator did not inform its Reliability Coordinator of four or more SOLs, or more than 15% of the SOLs whichever is less, which, while not IROLs, have been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis**.**
R9	N/A	N/A	N/A	The Transmission Operator exceeded a System Operating Limit (SOL), as identified in Requirement R8, for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R10	N/A	N/A	N/A	The Transmission Operator did not inform its Reliability Coordinator of actions being taken to return the system to within limits when an IROL, or an SOL identified in Requirement R8, had been exceeded.

	Lower	Moderate	High	Severe
R11	N/A	N/A	N/A	The Transmission Operator did not act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Revisions pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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1. SAR version 1 posted on May 15, 2007.
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4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.
11. Sixth posting of revised standard on December 14, 2011.
12. Seventh posting of revised standard on March 22, 2012.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that three requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements and will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	2Q12

Definitions of Terms Used in Standard

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that Transmission Operators have plans for operating within specified limits.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include, but is not limited to, dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include, but it is not limited to, plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audits

Self-Certifications

Spot Checking

Compliance Investigations

Self-Reporting

Complaints

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement for a rolling six-month period for analyses, the most recent 90 calendar days for voice recordings, and 12 months for operating logs and e-mail records, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis that represented projected System conditions allowing it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one NERC-registered entity, or 5% or less of the	The Transmission Operator did not notify two NERC-registered entities, or more than 5%, and	The Transmission Operator did not notify three NERC-registered entities, or more than 10% and	The Transmission Operator did not notify four or more NERC-registered entities, or more

	NERC-registered entities, whichever is less identified in the plan(s) cited, as to their role in the plan(s).	less than or equal to 10% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	less than or equal to 15% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	than15% of the NERC-registered entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
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~~11.~~12. Seventh posting of revised standard on March 22, 2012.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008 following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. ~~-~~As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that ~~3~~ three requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements and will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	~~3~~2Q12

Definitions of Terms Used in Standard

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operations Planning**

2. **Number:** TOP-002-3

3. **Purpose:** To ensure that Transmission Operators have plans for operating within specified limits.

4. **Applicability**

   4.1. Transmission Operator.

5. **Effective Date:** All requirements will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption.

B. Requirements

R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R2. Each Transmission Operator shall develop a plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall have evidence of a completed Operational Planning Analysis in accordance with Requirement R1. Such evidence could include, but is not limited to, dated power flow study results.

M2. Each Transmission Operator shall have evidence that it has developed a plan to operate within each IROL and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1 in accordance with Requirement R2. Such evidence could include, but it is not limited to, plans for precluding operating in excess of each IROL and each SOL which, while not an IROL, was identified as a result of the Operational Planning Analysis.

M3. Each Transmission Operator shall have evidence that it notified all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in the plan(s) in accordance with Requirement R3. Such evidence could include but is not limited to dated operator logs, voice recordings, or e-mail records.

D. Compliance

1. Compliance Monitoring Process

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Compliance Audits

Self-Certifications

Spot Checking

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The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Transmission Operator shall keep data or evidence to show compliance for each Requirement for a rolling six-~~-~~month period for analyses, the most recent ~~three months~~90 calendar days for voice recordings, and 12 months for operating logs and e-mail records, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Operator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Transmission Operator did not have an Operational Planning Analysis that represented projected System conditions allowing it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R2	N/A	N/A	N/A	The Transmission Operator did not develop a plan to operate within those IROLs and each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting its internal area reliability, identified as a result of the Operational Planning Analysis performed in Requirement R1.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not notify one NERC~~–~~-registered entity, or 5% or less of the	The Transmission Operator did not notify two NERC~~–~~-registered entities, or more than 5%, and	The Transmission Operator did not notify three NERC-registered entities, or more than	The Transmission Operator did not notify four or more NERC-registered entities, or more

	NERC-registered entities, whichever is less identified in the plan(s) cited, as to their role in the plan(s).	less than or equal to 10% of the NERC-registered entities, whichever is less, identified in the plan(s) as to their role in the plan(s).	10% and less than or equal to 15% of the NERC-registered entities, -whichever is less, identified in the plan(s) as to their role in the plan(s).	than15% of the NERC-registered entities identified in the plan(s) as to their role in the plan(s).

E. Regional Variances

None identified.

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There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their operational planning and Real-time monitoring responsibilities.

4. **Applicability**

   4.1. Transmission Operator.

   4.2. Balancing Authority.

   4.3. Generator Owner.

   4.4. Generator Operator.

   4.5. Interchange Authority.

   4.6. Load-Serving Entity.

   4.7. Transmission Owner.

   4.8. Distribution Provider.

5. **Effective Date:** All requirements, except Requirement R5, will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements, except Requirement R5, become effective the first day of the first calendar quarter ten months following Board of Trustees' adoption. Requirement R5 will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R5 becomes effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

1.2. A mutually-agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. A mutually-agreeable format.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

R3. Each Transmission Operator shall distribute its data specification, as developed in Requirement R1,to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority shall distribute its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall make available its dated, current, in-force documented specification for data in accordance with Requirement R1.

M2. Each Balancing Authority shall make available its dated, current, in-force documented specification for data in accordance with Requirement R2.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification, as developed in Requirement R1,to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their Operational Planning Analyses and Real-time monitoring, in accordance with Requirement R1 and Measurement M1, as well as any documents in force since the last compliance audit.

- Each Balancing Authority shall retain its dated, current, in-force, documented specification for the data necessary for it to perform their analysis functions and Real-time monitoring, in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.

- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R1 to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R3 and Measurement M3.

- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90 calendar days that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.
R2	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring. OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring	The Transmission Operator did not distribute its data specification, as developed in requirement R1 to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring

	process used in meeting its NERC-mandated reliability requirements.	Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	process used in meeting its NERC-mandated reliability requirements.
For the Requirement R4 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R4	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements .	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to four or more entities, or more than 15% of the entities, whichever is less,that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.
R5	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

E. **Regional Variances**
None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.
11. Sixth posting of revised standard on December 14, 2011.

~~11.~~12. Seventh posting of revised standard on March 22, 2012.

Proposed Action Plan and Description of Current Draft:
The SDT began meeting in January 2008, following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. -As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that ~~3~~ three requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements and will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	~~3~~2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **Operational Reliability Data**

2. **Number:** TOP-003-2

3. **Purpose:** To ensure that the Transmission Operator and Balancing Authority have the data needed to fulfill their operational planning and Real-time monitoring responsibilities.

4. **Applicability**

   4.1. Transmission Operator.

   4.2. Balancing Authority.

   4.3. Generator Owner.

   4.4. Generator Operator.

   4.5. Interchange Authority.

   4.6. Load-Serving Entity.

   4.7. Transmission Owner.

   4.8. Distribution Provider

5. **Effective Date:** All requirements, except Requirement R5, will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements, except Requirement R5, become effective the first day of the first calendar quarter ten months following Board of Trustees' adoption. Requirement R5 will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirement R5 becomes effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements

R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-time monitoring.

1.2. A mutually-agreeable format.

1.3. A periodicity for providing data.

1.4. The deadline by which the respondent is to provide the indicated data.

R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The specification shall include: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring.

2.2. A mutually-agreeable format.

2.3. A periodicity for providing data.

2.4. The deadline by which the respondent is to provide the indicated data.

R3. Each Transmission Operator shall distribute its data specification, as developed in Requirement R1,to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R4. Each Balancing Authority shall distribute its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

C. Measures

M1. Each Transmission Operator shall make available its dated, current, in-force documented specification for data in accordance with Requirement R1.

M2. Each Balancing Authority shall make available its dated, current, in-force documented specification for data in accordance with Requirement R2.

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification, as developed in Requirement R1,to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements in accordance with Requirement R3. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specifications for data, in accordance with Requirement R5. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Process

- For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.
- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

1.2. Compliance Monitoring and Enforcement Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.3. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each responsible entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Transmission Operator shall retain its dated, current, in-~~-~~force, documented specification for the data necessary for it to perform their Operational Planning Analyses and Real-time monitoring, in accordance with Requirement R1 and Measurement M1, as well as any documents in force since the last compliance audit.

- Each Balancing Authority shall retain its dated, current, in-~~-~~force, documented specification for the data necessary for it to perform their analysis functions and Real-time monitoring, in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.

- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R1 to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R3 and Measurement M3.

- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its data specification as developed in Requirement R2 to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements, in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall retain evidence for the most recent 90 calendar days that it has satisfied the obligations of the documented specifications for data~~,~~ in accordance with Requirement R5 and Measurement M5.

If a responsible entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or the time period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Additional Compliance Information

None

2. Violation Severity Levels

	Lower	Moderate	High	Severe
R1	The Transmission Operator did not include one of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include two of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.4) of the documented specification for the data necessary for them to perform their Operational Planning Analyses and Real-time monitoring. OR, The Transmission Operator did not include a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring.
R2	The Balancing Authority did not include one of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include two of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.4) of the documented specification for the data necessary for them to perform their analysis functions and Real-time monitoring. OR, The Balancing Authority did not include a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring.
For the Requirement R3 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R3	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring	The Transmission Operator did not distribute its data specification, as developed in requirement R1 to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is less, that have data required by the Transmission Operator's Operational Planning	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is less, that have data required by the	The Transmission Operator did not distribute its data specification, as developed in Requirement R1 to four or more entities, or more than 15% of the entities, whichever is less, that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring

	process used in meeting its NERC-mandated reliability requirements.	Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	process used in meeting its NERC-mandated reliability requirements.
For the Requirement R4 VSL only, the intent of the SDT is to start with the Severe VSL first and then to work your way to the left until you find the situation that fits. In this manner, the VSL will not be discriminatory by size of entity. If a small entity has just one affected reliability entity to inform, the intent is that that situation would be a Severe violation.				
R4	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to one entity, or 5% or less of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements~~-~~.	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is less, that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements .	The Balancing Authority did not distribute its data specification, as developed in Requirement R2 to four or more entities, or more than 15% of the entities, whichever is less,that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements.
R5	N/A	N/A	N/A	The responsible entity receiving a data specification in Requirement R3 or R4 did not satisfy the obligations of the documented specifications for data.

E. **Regional Variances**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	TBD	Changes pursuant to Project 2007-03	Revised

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2007-03 Real-time Operations

Prerequisite Approvals

Some changes made in this project are dependent on corresponding changes being approved in:

- Project 2006-06, Reliability Coordination:
  - IRO-001-3 - Reliability Coordination – Responsibilities and Authorities
  - IRO-005-4 - Reliability Coordination – Current Day Operations
- Project 2007-09, Generator Verification:
  - MOD-025-2 - Verification and Data Reporting of Generator Real and Reactive Power Capability

TOP-001-2: Transmission Operations, TOP-002-3: Operations Planning and TOP-003-1: Operational Reliability Data cannot be implemented until all three of the above standards have been implemented.

Revision to Sections of Approved Standards and Definitions

There are no new definitions in the proposed set of standards.

Two drafting teams (Project 2006-06 and Project 2007-03) have coordinated on a common definition of Reliability Directive and agreed that the Reliability Coordination Standards Drafting Team (Project 2006-06) would write the definition and post it for vetting by the industry. The agreed upon definition is included here for ease of reference.

> **Reliability Directive** - A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impacts.

Compliance with Standard

There are three standards associated with this project for which industry approval will be requested: TOP-001-2: Transmission Operations, TOP-002-3: Operations Planning, and TOP-003-1: Operational Reliability Data.

Standard	Functions that must Comply with the Associated Requirements							
	TOP	BA	GO	GOP	IA	LSE	DP	TO
PER-001-0: Operating Personnel Responsibility and Authority	Retired							

TOP-001-2: Transmission Operations	X	X		X		X	X	
TOP-002-3: Operations Planning	X							
TOP-003-1: Operational Reliability Data	X	X	X	X	X	X	X	X
TOP-004-2: Real-Time Transmission Operations	Retired							
TOP-005-2: Operational Reliability Data	Retired							
TOP-006-1: Monitoring System Conditions	Retired							
TOP-007-0: Reporting System Operating Limits (SOL) and Interconnection Reliability Operating Limit (IROL) Violations	Retired							
TOP-008-1: Response to Transmission Limit Violations	Retired							
PRC-001-2	Retired Requirements R2, R5, and R6.							

The effective date is the date entities are expected to meet the performance identified in these standards. Note that entities have been given several months beyond the regulatory approval date (preparation time) to fully comply with new requirements.

Effective Date of Revised Standards

All requirements except TOP-003-2, Requirements R1 and R2 will become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all the requirements except TOP-003-2, Requirements R1 and R2 become effective the first day of the first calendar quarter twelve months following Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Requirements R1 and R2 of TOP-003-2 will become effective the first day of the first calendar quarter ten months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 and R2 of TOP-003-2 become effective the first day of the first calendar quarter ten months following Board of Trustees approval.

The twelve month period is to allow for entities to update processes and train operators on the revised requirements. The two month differential for TOP-003-2, Requirements R1 and R2 is to provide time for recipients of a data specification to respond to the request for data.

Retirement Date for Existing Standards

The existing Standards shall be retired at midnight of the day immediately prior to the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements will be retired at midnight of the day immediately prior to the first day of the first calendar quarter twelve months following Board of Trustees adoption.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Note: The Project 2007-03 SDT is recommending retirement of three requirements in PRC-001-1 because those requirements address data and data requirements which is covered in TOP-003-2. This redline shows the retired requirements, and a mapping document showing the approved requirements in PRC-001 and the proposed disposition of those requirements is posted on the Project 2007-03 page. The ballot of the conforming changes to PRC-001 is associated with the approval of TOP-003-2 and the implementation plan for this project.

More complete revisions to PRC-001 are addressed in the scope of Project 2007-06 SDT.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.
11. Sixth posting of revised standard on December 14, 2011.
12. Seventh posting of revised standards on March 22, 2012.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008, following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that three requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-2

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. *[Violation Risk factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R2.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R2.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 2, 2.1, and 2.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall be responsible for compliance monitoring.

1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

If an entity is found non-compliant, the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.3. Compliance Monitoring and Assessment Processes

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Reqmt. #	VRF	Time Horizon	Lower	Moderate	High	Severe
R1	High	Operations Planning, Same-day Operations, Real-time Operations	N/A	N/A	The responsible entity failed to be familiar with the limitations of protection system schemes applied in its area.	The responsible entity failed to be familiar with the purpose of protection system schemes applied in its area.
R2	N/A	N/A	N/A	N/A	N/A	N/A
R2.1	High	Operations Planning, Same-day Operations, Real-time Operations	The Generator Operator failed to coordinate one new protective system or protective System change with either its Transmission Operator or its Host Balancing Authority or both.	The Generator Operator failed to coordinate two new protective systems or protective System changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate three new protective systems or protective System changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate more than three new protective systems or protective System changes with its Transmission Operator or its Host Balancing Authority, or both.
R2.2	High	Operations Planning, Same-day Operations, Real-time Operations	The Transmission Operator failed to coordinate one new protective system or protective System change with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate two new protective systems or protective System changes with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate three new protective systems or protective System changes with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate more than three new protective systems or protective System changes with neighboring Transmission Operators or Balancing Authorities, or both.
R3	High	Operations Planning, Same-day	The Transmission Operator failed	The Transmission Operator failed	The Transmission Operator failed	The Transmission Operator failed

		Operations, Real-time Operations	to coordinate protection Systems on major transmission lines and interconnections with one of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	to coordinate protection Systems on major transmission lines and interconnections with two of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	to coordinate protection Systems on major transmission lines and interconnections with three of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	to coordinate protection Systems on major transmission lines and interconnections with three or more of its neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Delete data requirements as they are now handled in TOP-003-2.	Deleted Requirements 2, 5, and 6.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Note: The Project 2007-03 SDT is recommending retirement of three requirements in PRC-001-1 because those requirements address data and data requirements~~,~~ which is covered in TOP-003-2. This redline shows the retired requirements, and a mapping document showing the approved requirements in PRC-001 and the proposed disposition of those requirements is posted on the Project 2007-03 page. The ballot of the conforming changes to PRC-001 is associated with the approval of TOP-003-2 and the implementation plan for this project.

More complete revisions to PRC-001 are addressed in the scope~~-~~ of Project 2007-06 SDT.

Development Steps Completed:

1. SAR version 1 posted on May 15, 2007.
2. SAR version 1 comment period closed on June 13, 2007.
3. SAR version 2 posted on August 7, 2007.
4. SAR version 2 comment period closed on September 7, 2007.
5. SAR approved by SC on November 1, 2007.
6. First posting of revised standards on October 7, 2008.
7. Second posting of revised standards on April 7, 2009.
8. Third posting of revised standards on August 25, 2009.
9. Fourth posting of revised standard on August 4, 2010.
10. Fifth posting of revised standard on April 26, 2011.
11. Sixth posting of revised standard on December 14, 2011.

~~11.~~12. Seventh posting of revised standards on March 22, 2012.

Proposed Action Plan and Description of Current Draft:

The SDT began meeting in January 2008, following the approval of the SAR by the SC. The original schedule showed completion of the project in 4Q09. ~~-~~As part of the proposed revisions, TOP-004-2, TOP-005-1, TOP-006-1, TOP-007-0, and TOP-008-0, and PER-001-0 will be retired. The requirements in those standards have been eliminated or moved to other standards within this project. The SDT is also recommending that ~~3~~ three requirements in PRC-0001-1 be retired due to the fact that those requirements deal with data and data requirements will be covered in the proposed TOP-003-2.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for successive ballot.	1Q12
2. Post for recirculation ballot.	2Q12
3. Submit to BOT.	~~3~~2Q12

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

There are no new or revised definitions proposed in this standard revision.

A. Introduction

1. **Title:** **System Protection Coordination**

2. **Number:** PRC-001-2

3. **Purpose:**

   To ensure system protection is coordinated among operating entities.

4. **Applicability**

   4.1. Balancing Authorities

   4.2. Transmission Operators

   4.3. Generator Operators

5. **Effective Date:** All requirements become effective the first day of the first calendar quarter twelve months following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, the requirements become effective the first day of the first calendar quarter twelve months following Board of Trustees' adoption.

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area. *[Violation Risk factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R2. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R2.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority. *[Violation Risk Factor: High][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R2.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

R3. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities. *[Violation Risk Factor: High]][Time Horizon: Operations Planning, Same-day Operations, Real-time Operations]*

C. Measures

M1. Each Generator Operator and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, revised fault analysis study, letters of agreement on settings, notifications of changes, or other equivalent evidence that will be used to confirm that there was coordination of new protective systems or changes as noted in Requirements 2, 2.1, and 2.2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

The Regional Entity shall be responsible for compliance monitoring.

~~1.2. Compliance Monitoring and Reset Time Frame~~

~~One or more of the following methods will be used to assess compliance:~~

- ~~Self-certification (Conducted annually with submission according to schedule.)~~
- ~~Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)~~
- ~~Periodic Audit (Conducted once every three years according to schedule.)~~
- ~~Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)~~

~~The Performance-Reset Period shall be 12 months from the last finding of non-compliance.~~

~~1.3.~~1.2. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

Each Generator Operator and Transmission Operator shall have current, in-force documents available as evidence of compliance for Measure 1.

If an entity is found non-compliant, the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

~~1.4.~~1.3. Compliance Monitoring and Assessment Processes

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)

- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

~~1.5.~~1.4. Additional Compliance Information

None.

2. Violation Severity Levels

Reqmt. #	VRF	Time Horizon	Lower	Moderate	High	Severe
R1	High	Operations Planning, Same-day Operations, Real-time Operations	N/A	N/A	The responsible entity failed to be familiar with the limitations of protection system schemes applied in its area.	The responsible entity failed to be familiar with the purpose of protection system schemes applied in its area.
R2	N/A	N/A	N/A	N/A	N/A	N/A
R2.1	High	Operations Planning, Same-day Operations, Real-time Operations	The Generator Operator failed to coordinate one new protective system or protective ~~system~~ System change with either its Transmission Operator or its Host Balancing Authority or both.	The Generator Operator failed to coordinate two new protective systems or protective ~~system~~ System changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate three new protective systems or protective ~~system~~ System changes with either its Transmission Operator or its Host Balancing Authority, or both.	The Generator Operator failed to coordinate more than three new protective systems or protective ~~system~~ System changes with its Transmission Operator or its Host Balancing Authority, or both.
R2.2	High	Operations Planning, Same-day Operations, Real-time Operations	The Transmission Operator failed to coordinate one new protective system or protective ~~system~~ System change with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate two new protective systems or protective ~~system~~ System changes with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate three new protective systems or protective ~~system~~ System changes with neighboring Transmission Operators or Balancing Authorities, or both.	The Transmission Operator failed to coordinate more than three new protective systems or protective ~~system~~ System changes with neighboring Transmission Operators or Balancing Authorities, or both.
R3	High	Operations Planning,	The Transmission	The Transmission	The Transmission	The Transmission

		Same-day Operations, Real-time Operations	Operator failed to coordinate protection ~~systems~~ Systems on major transmission lines and interconnections with one of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	Operator failed to coordinate protection ~~systems~~ Systems on major transmission lines and interconnections with two of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	Operator failed to coordinate protection ~~systems~~ Systems on major transmission lines and interconnections with three of its neighboring Generator Operators, Transmission Operators, or Balancing Authorities.	Operator failed to coordinate protection ~~systems~~ Systems on major transmission lines and interconnections with three or more of its neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	August 25, 2005	Fixed Standard number in Introduction from PRC-001-1 to PRC-001-0	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	TBD	Delete data requirements as they are now handled in TOP-003-2.	Deleted Requirements 2, 5, and 6.

Resolution of Issues Assigned to Project 2007-03 Real-time Operations Standard Drafting Team

Standard	Source	Language	Resolution
TOP-001			
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started. The TOP standards have been re-written to specifically address what a Transmission Operator is responsible for. The proposed TOP requirements are no longer restricted to the undefined term 'operating emergency' and are now more inclusive and stringent than the previous requirement. Indeed, the undefined term 'operating emergency' is no longer utilized in the proposed revisions. Therefore, any delay in defining operating states in the EOP Project has no effect on the TOP standards.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may	This is covered in proposed TOP-001-2, Requirement R5.

Standard	Source	Language	Resolution
		notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	Requirement using this term was deleted as not needed in a reliability standard. The standards already require the necessary actions.
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been re-written to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03 which has not yet started.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.
TOP-002			
TOP-002-2	FERC Order 693	1600 - Address critical energy infrastructure confidentiality as part of the routine standard development process.	Restrictions due to confidentiality have been eliminated by re-writing the data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
TOP-00-2	FERC Order 693	1601 – Require next day analysis for all IROLs to identify and communicate control actions to system operators	See proposed TOP-002-3, Requirements R1, R2, and R3.
TOP-002-2	FERC Order 693	1603 - Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-002-2	FERC Order 693	1604/1608 - Requires simulation contingencies to match what will actually happen in the field.	This is covered in proposed TOP-002-3, Requirement R1 by the phrase "and shall represent projected System conditions".
TOP-002-2	FERC Order 693	1606 - Commenters did not take issue with the proposed interpretation of the term "deliverability" as "the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches."[1] The Commission adopts this proposed	Deliverability and limits are included in Operational Planning Analysis in TOP-002-3, Requirement R1. Operational Planning Analysis contains deliverability and much more and is thus more stringent than the Order. Limit violations in the Operational Planning Analysis will show any deliverability problems regardless of type and proposed requirements mandate

[1] Id. at P 974.

Standard	Source	Language	Resolution
		interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	that these issues be resolved. In addition, the proposed requirements clearly state that an individual entity, the Transmission Operator, is wholly responsible for these concerns which is an improvement over the previous vaguely worded requirement that placed this responsibility with the Balancing Authority which has no control over the issues involved.
TOP-002-1	Fill in the Blank Team	Remove "in accordance with NERC, Regional Reliability Organization, sub-regional, and local reliability requirements" from R6 and "in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes" from R12 .	Requirement R6 has been deleted. For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. Requirement R12 has been deleted as duplicative of MOD-030-2 (not yet approved).
TOP-002-2: R19	NERC Audit Observation Team	How do you address the term - verify "Accurate"	Requirement R19 was eliminated as unmeasurable.
TOP-002-2	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1.
TOP-002-1	Version 0 Team	Define N-1	Requirement R6 has been deleted.

Standard	Source	Language	Resolution
			For the Balancing Authority – deleted as not applicable as the Balancing Authority needs only respond to CPS and DCS. For the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. This term is no longer in use for this standard.
TOP-002-1	Version 0 Team	Define ‘without intentional delay’	This term was considered unmeasurable and has been deleted from this standard.
TOP-002-1	Version 0 Team	Reliability should ‘trump’ confidentiality	The SDT has removed all references to confidentiality by re-writing the data specification requirements.
TOP-002-1	Version 0 Team	Coordination of planning required	The SDT has re-written and tightened up the requirements for distributing data and information.
TOP-002-1	Version 0 Team	Limit of 2 tests per year	This requirement has been deleted by the SDT as verification testing is not needed in this standard.
TOP-002-1	VRF Team	R9 – related to INT-003	Requirement R9 has been deleted as it is duplicative of approved INT-003-2
TOP-002-1	VRF Team	R14 & 14.1 – ambiguous	Deleted – duplicative of proposed TOP-003-2.
TOP-002-1	VRF Team	R2 – administrative in nature, not a real requirement	The SDT agreed and deleted this requirement.
		TOP-003	
TOP-003-0	FERC Order 693	1620 & 1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability	The SDT posed a question on this issue as a fact finding exercise in the second posting of this project in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – “The ERO should utilize the information filed by

Standard	Source	Language	Resolution
		Standard to incorporate an appropriate lead time for planned outages.	commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. After reviewing the industry comments, the SDT concluded that proposed TOP-001-2, Requirements R5 & R6 adequately cover this issue. The SDT bases this position on the requirement which includes the Operations Planning Time Horizon that covers the period from one day to one year. The requirement mandates that actions are coordinated. The SDT interprets this to include planned outages when they are known. Therefore, the SDT has not included a standard lead time in the revised requirements.
TOP-003-0	FERC Order 693	1622 - Consider TVA's suggestion for including breaker outages within the	New data specifications in proposed TOP-003-2 handle this concern.

Standard	Source	Language	Resolution
		meaning of facilities that are subject to advance notice for planned outages.	
TOP-003-0	FERC Order 693	1624 - Require any facility, that in the opinion of the reliability coordinator, balancing authority, or transmission operator, will have a direct impact on the reliability of the bulk power system be subject to the requirement R1 for planned outage coordination.	New data specifications in proposed TOP-003-2, Requirement R1 (and bullets) handle this concern.
TOP-003-0	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R5 of PRC-001-1 in TOP-002 R1, R3, R4, or R5 or TOP-003 R1, R3, R4	See proposed TOP-003-2, Requirement R1
TOP-003-0	Version 0 Team	Outage information needed sooner than 1 day prior	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	Version 0 Team	RA can't request outage cancellation	Deleted – now covered in Project 2006-06.
TOP-003-0	Version 0 Team	Submit outage data ASAP but no later than noon day ahead	New data specifications in proposed TOP-003-2 handle this concern.
TOP-003-0	VRF Team	R4 – poorly written	Deleted – now covered in Project 2006-06.
TOP-003-1	FMPA – Frank Gaffney	With respect to requirement R1.2, why is the TOP responsible for providing generator outage information? Isn't that the BA's or GOP's responsibility and isn't this redundant with IRO-010-1?	Requirement deleted as duplicative of proposed TOP-003-2, R1.

Standard	Source	Language	Resolution
TOP-004			
TOP-004-1	FERC Order 693	1636 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	Replaced by proposed TOP-001-2, R7 through R11. T_v is more stringent than the existing 30 minute requirement for IROLs and 30 minutes is retained for selected SOLs. Unknown states, in this context, cannot exist because valid operating limits have been determined for all Facilities in a TOP's footprint. The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to Emergencies.
TOP-004-1	FERC Order 693	1637 - Reliability coordinators should report any IROL violations to NERC on a monthly basis for one year beginning August 2, 2007.	Not within the scope of the SDT.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (. . .the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or	The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the bulk power system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

Standard	Source	Language	Resolution
		periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under . . . high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	FERC Order 693	1639 - Consider Santa Clara's comments regarding changes to requirement R2 in the standards development process. (Santa Clara states that Requirement R2 of the Reliability Standard should be revised to include frequency monitoring in addition to the monitoring of voltage, real and reactive power flows.)	This is covered as part of the new data specification requirements in proposed TOP-003-2 for the Transmission Operator & Balancing Authority. The Reliability Coordinator is covered by proposed IRO-010-1, Requirement R3.
TOP-004-1	FERC Order 693	1641 - NERC should report the results of the survey to the Commission within 18 months	Not within the scope of the SDT.

Standard	Source	Language	Resolution
		of the effective date of this rule.	
TOP-004-1	Fill in the Blank Team	No action required	No action required.
TOP-004-1	Version 0 Team	Operations should conform to planning standards	Operations and planning are different timeframes with different problems and solutions
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	Requirement moved to proposed TOP-001-2, Requirement R5 and clarified.
TOP-004-1	Version 0 Team	Define SOL & IROL	These are defined terms in the NERC Glossary.
TOP-004-1	Version 0 Team	Clarify roles	Applicability has been reviewed and updated as necessary.
TOP-004-1	Version 0 Team	Define (or remove) practical	The term has been removed.
TOP-004-1	Version 0 Team	Specify disconnection as acceptable in R5	The requirement has been deleted. Relationships between the Reliability Coordinator and Transmission Operator as described in the revised standards cover these actions.
TOP-005			
TOP-005-1	FERC Order 693	1648 - Include information about the operational status of special protection systems and power system stabilizers in Attachment 1.	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.
TOP-005-1	FERC Order 693	1649 - Delete references to confidentiality agreements but ensure critical energy infrastructure confidentiality is addressed in the standards development process.	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	FERC Order 693	1650 - Consider FirstEnergy’s modifications to Attachment 1 and ISO-NE’s recommended revision to requirement R4 in the standards	Attachment 1 has been deleted and replaced by the new data specification requirement in proposed TOP-003-2.

Standard	Source	Language	Resolution
		development process. ISO-NE recommends that the reference to "purchasing-selling entity" in Requirement R4 should be replaced with "generator owner, transmission owner, and LSE.	Requirement R4 has been superseded by proposed TOP-003-2 which does include the indicated entities.
TOP-005-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards. Consider putting R2 of PRC-001-1 in TOP-005. Note: These requirements are being removed from PRC.	See proposed TOP-003-2, Requirement R1
TOP-005-1	Version 0 Team	Need to include GO & LSE	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Data update is too slow	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	Generator data should include voltage control & stabilizers	New data specifications in proposed TOP-003-2 handle this concern.
TOP-005-1	Version 0 Team	GO needs to supply data to BA & TO	New data specifications in proposed TOP-003-2 handle this concern
TOP-005-1	Received for the November 4, 2009 Technical Conference on Interpretations of Standards	NERC staff believes that the interpretation does not support the stated purpose of IRO-005-1: "The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The	While this issue was entered against the Transmission Operator as the interpretation request was primarily for TOP-005-1, the emphasis on such informative actions has shifted in current revision projects. The proposed IRO-010-1, Requirement R1 gives the Reliability Coordinator the right to ask for any reliability related data that they need to perform their Reliability Coordinator task.

Standard	Source	Language	Resolution
	from Manitoba Hydro	Reliability Coordinator must monitor BES parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas." Given that Requirement R12 pre-supposes that the SPS is armed to address inter-Balancing Authority or inter-Transmission Operator impacts (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation), the argument not discussed in the interpretation is that the SPS itself with one communication channel in service can be viewed for advance planning or reliability assessment purposes as a single contingency (loss of the communication channel). The question asked by the requestor indicates that the operation of the SPS on a single channel is known ahead of the timeframe for which the SPS may be armed and that the condition was not first identified when the SPS was called to operate. In this regard, the Reliability Coordinator must be aware of the less dependable state of the SPS in order to properly assess the impact and plan for the next single contingency that it conceivably could	And it also mandates the Transmission Operator to provide said data in Requirement R3. (Note – This standard has been approved by the BOT but has not yet been approved by FERC.)

Standard	Source	Language	Resolution
		experience. In this case, the Reliability Coordinator may wish to consider the loss of an armed SPS when performing its reliability assessments. While the Reliability Coordinator may not elect to proactively position the system to withstand the loss of the SPS that is operating on a single communication channel, the Reliability Coordinator may elect to develop a contingency plan in the event the SPS does fail to operate as designed or if the remaining communication channel is lost. The importance of the SPS relative to current or anticipated system conditions would be considerations for the Reliability Coordinator. This consideration only becomes possible if the Transmission Operator notifies the Reliability Coordinator that the SPS is operating on a single communication channel. Therefore, Transmission Operator notification to the Reliability Coordinator of this condition raises the Reliability Coordinator's situational awareness that may influence current or future operating conditions or decisions in a preventive rather than reactive manner. NERC staff does agree that the SPS	

Standard	Source	Language	Resolution
		is still mission capable with only one communication channel in service, but degraded in terms of its dependability due to the unavailability of redundant communications channels. The fact that a second communications channel was part of the original design of the SPS suggests that both channels were important to the dependability of the system, and that the unavailability of either channel causes some degradation in the overall dependability of the SPS. Additionally, the team equated “any degradation” with “potential failure to operate as expected” in IRO-005. The use of the term “or” connecting these two phrases in the standard indicates these were not intended to be equivalent. Therefore, NERC staff believes the conclusion reached by the team that the two terms are synonymous is incorrect. Further, the specific circumstances contemplated in the interpretation request are not likely to occur often and the additional burden to Transmission Operators to notify the Reliability Coordinator is de minimis when compared to the improved situational awareness that would result. On	

Standard	Source	Language	Resolution
		this basis, NERC staff believes the interpretation is not serving the best interests of reliability and should be remanded to the team for further consideration of the NERC staff opinion.	
TOP-006			
TOP-006-1	FERC Order 693	1660 & 1661 - Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system.	Minimum capabilities for Transmission Operators are being handled in project 2009-02, Real-time Monitoring and Analysis Capabilities. Requirement for phase angle information is covered by proposed TOP-003-2.
TOP-006-1	FERC Order 693	1663 - Clarify the meaning of “appropriate technical information” concerning protective relays. To provide more clarity, criteria that define what “appropriate technical information” is necessary should be specified so that operators can make better informed decisions.	This term is no longer used. Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and TOP-003-2 (data).
TOP-006-1	FERC Order 693	1664 - Consider APPA’s comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
TOP-006-1	NERC Standards DT Coordinators	Requirements R2, R5, and R6 (for coordination in real-time) of PRC-001-1 System Protection Coordination are better addressed in the TOP family of standards.	See proposed TOP-003-2, Requirement R1

Standard	Source	Language	Resolution
		Consider putting R6 of PRC-001-1 in TOP-003 R5 or TOP-006. Note: These requirements are being retired in PRC-001-1.	
TOP-006-1	Version 0 Team	Need to match roles with FM	Applicability has been reviewed by the SDT and changed as required in accordance with the FM and the Compliance Registry.
TOP-006-1	Version 0 Team	Monitor frequency at multiple points	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	Load forecasting data required	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	Version 0 Team	GO needs to provide normal & emergency data	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R1, 1.1, 1.2 – 'available in emergency situation' may be needed	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-1	VRFs Team	R3 – define appropriate	This requirement was deleted as duplicative of approved PRC-001-1, Requirement R1.
TOP-006-1	VRFs Team	R4 – What information is required and what is a load pattern?	New data specifications in proposed TOP-003-2 handle this concern.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirements R1 and R1.2, why are BAs responsible for information regarding transmission resources available for use? Isn't that the role of the TOP?	Deleted – covered as part of the new data specification requirements in proposed TOP-003-2.
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R2, why is the BA responsible for monitoring transmission line status, voltage, load tap changer settings, and reactive power in general?	Deleted – SDT agrees.

Standard	Source	Language	Resolution
		Monitoring and managing reactive resources, voltage and tap settings is clearly made the responsibility of the TOP in VAR-001-1a.	
TOP-006-2	FMPA – Frank Gaffney	With respect to requirement R3 why does the BA need to understand protective relaying? Isn't that the role of the TOP and GOP?	Requirement R3 deleted as duplicative of proposed PER-005-1 (training) and proposed TOP-003-2 (data).
TOP-007			
TOP-007-0	FERC Order 693	1673 - Consider the NRC's comments on voltage requirements as part of the standards development process.	Next day analysis is required in proposed TOP-002-3, R1. A specified minimum voltage limit is by definition an SOL which must be studied in proposed TOP-002-3, Requirement R1. Additionally, approved NUC-001-2, Requirements R3 & R4.1 require the transmission entity to incorporate NPIRs in their planning and operating analyses. Approved FAC-011-2 and approved FAC-014-2, Requirement R2 require the Transmission Operator to incorporate SOLs into their analyses. All data required for Operational Planning Analyses is stipulated in proposed TOP-003-2. Approved NUC-001-2, Requirements R3 & R8 covers the information flowing back to the nuclear plant operator.
TOP-007-0	Version 0 Team	Need to define evidence of evaluation	This term isn't used in the requirements – no action required.
TOP-007-0	Version 0 Team	Need to tighten the non-compliance terms	Measures and VSL have been assigned to all requirements.
TOP-007-0	Version 0 Team	Not enforceable with current criteria	Not enough information provided to address concern.
TOP-007-0	Version 0 Team	RA should be included	Reliability Coordinator is now covered in Project 2006-06.

Standard	Source	Language	Resolution
TOP-007-0	Version 0 Team	More of a compliance issue than a true standard	Not enough information provided to address concern.
		TOP-008	
TOP-008-1	FERC Order 693	1681 - Consider APPA's comments regarding missing measures in the standards development process.	Measures have been assigned to all requirements.
		PER-001	
PER-001-0	Version 0 Team	Data retention should be 1 year	This standard will be retired.
		Transferred from Project	
PRC-001	Project 2007-06	1441- S- Ref 10339 - Clarify the term corrective action. 1440. We believe that [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System. 1441. We direct the ERO to clarify the term corrective action consistent with this discussion when it modifies PRC-001-1 in the Reliability Standards development process.	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations.
PRC-001	Project 2007-06	1444 - S- Ref 10340 - Consider First Energy and the California PUCs comments about the	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations. The

Standard	Source	Language	Resolution
		maximum time for corrective actions in the standards development process. 1428. California PUC contends that imposing a time restriction for returning a system to a stable state may cause more harm than good since additional information and options may be available as time elapses. It repeats its suggestion from its earlier comments on the Staff Preliminary Assessment and proposes the following alternative language: Transmission or generation operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible, and no longer than 30 minutes, except where a longer response time is feasible, or where a longer response is demonstrated to produce a better ultimate solution without unacceptable interim risk. 1431. FirstEnergy contends that Requirement R2.1 essentially requires generator operators to report all protective relay or equipment failures, since generator operators may not be able to tell which failures will reduce system reliability. FirstEnergy suggests that R2.1 should be	Transmission Operator is the true functional entity responsible here. Covered as part of the new data specification requirements in proposed TOP-003-2.

Standard	Source	Language	Resolution
		revised to require generator operators to report all equipment failures or outages. FirstEnergy further suggests that PRC-001-1 be revised to provide that if a company performs reasonable testing procedures, undiscoverable equipment failures will not be violations of R2.1	
PRC-001	Project 2007-06	1449 - S- Ref 10341 - Upon detection of failures in relays or protection system elements on the bulk power system that threaten reliability, relevant transmission operators must be informed promptly, but within a specified period of time. -- (2) a requirement that transmission and generator operators be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities could carry out appropriate corrective control actions consistent with those used in mitigating IROL violations.	Covered as part of the new data specification requirements in proposed TOP-003-2.
PRC-001	Project 2007-06	1449 - S- Ref 10343 - Para 1420. Once informed, transmission operators must carry out corrective control actions that return the system to a stable state that respects system requirements as soon as possible and no	Covered in TOP-001-2, Requirement R11.

Standard	Source	Language	Resolution
		longer than 30 minutes. 1440. [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.	

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-03 Real-time Operations

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001-2 – Transmission Operations, TOP-002-3 – Operations Planning, and TOP-003-2 – Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in TOP-001-2, TOP-002-3, TOP-003-2:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a Cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or Cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or Cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or Cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Eemergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report
The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the bulk power system.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the bulk power system:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eleven requirements in TOP-001-2. None of the eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, R4, R7, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1.1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Not informing a Transmission Operator of the inability to perform a Reliability Directive could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render Emergency assistance could lead to bulk power system instability, separation or Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or Cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R6 has been assigned a Medium VRF and is the replacement for proposed TOP-003-1, Requirement R3 which was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system, regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or Cascading failures

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to operating within the IROL.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R7 mandates that entities operate within each identified IROL and its associated IROL T_v. By definition, if an entity fails to do so, bulk power system instability, separation, or Cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R8 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or Cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R9 mandates that entities operate within each identified local SOL. Since local SOLs in Requirement R9, by definition, can't cause bulk power system instability, separation, or Cascading this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, Requirements R7 and R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or Cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, Requirements R7, R9, and R11 and this requirement is a simple notification requirement for informational purposes only. Therefore, bulk power system instability, separation, or Cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. It is also

similar to proposed TOP-001-2, Requirement R7 which has been assigned a High VRF. Therefore, there is consistency among Reliability Standards.

- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities act or direct others to act to mitigate the magnitude and duration of exceeding an IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or Cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-3, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved IRO-001-1.1, Requirement R8. That VSL has a Moderate violation for not complying with the Reliability Coordinator's directive for a valid reason but not informing the Reliability Coordinator of this fact. It then goes on to establish a Severe VSL for not complying with the directive. The SDT found little reason to separate out a Moderate VSL for not informing	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		the Transmission Operator. Whether it was for a valid reason or not, the consequences of the Transmission Operator not being aware of the fact that the directive was not being followed are potentially catastrophic. Therefore, the SDT has proposed only a Severe VSL and this VSL I more stringent than the VSL cited. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1.1a, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-004-2, Requirement R1. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		Therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Violation Risk Factor and Violation Severity Level Assignments

Project 2007-03 Real-time Operations

Violation Risk Factor and Violation Severity Level Assignments

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in TOP-001-2 – Transmission Operations, TOP-002-3 – Operations Planning, and TOP-003-2 – Operational Reliability Data.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

Justification for Assignment of Violation Risk Factors in TOP-001-2, TOP-002-3, TOP-003-2:

The SDT applied the following NERC criteria when proposing VRFs for the requirements in TOP-001-2:

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to ~~bulk~~ Bulk ~~electric~~ Electric ~~system~~ System instability, separation, or a ~~cascading~~ Cascading sequence of failures, or could place the ~~bulk electric system~~Bulk Electric System at an unacceptable risk of instability, separation, or ~~cascading~~ Cascading failures; or, a requirement in a planning time frame that, if violated, could, under ~~emergency~~Emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to ~~bulk electric system~~Bulk Electric System instability, separation, or a ~~cascading~~ Cascading sequence of failures, or could place the ~~bulk electric system~~Bulk Electric System at an unacceptable risk of instability, separation, or ~~cascading~~ Cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the ~~bulk electric system~~Bulk Electric System, or the ability to effectively monitor and control the ~~bulk electric system~~Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to ~~bulk electric system~~Bulk Electric System instability, separation, or ~~cascading~~ Cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System, or the ability to effectively monitor, control, or restore the ~~bulk electric system~~Bulk Electric System. However, violation of a medium risk requirement is unlikely, under ~~emergency~~Emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to ~~bulk electric system~~Bulk Electric System instability, separation, or ~~cascading~~ Cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System, or the ability to effectively monitor and control the ~~bulk electric system~~Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the Eemergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the ~~bulk electric system~~Bulk Electric System, or the ability to effectively monitor, control, or restore the ~~bulk electric system~~Bulk Electric System. A planning requirement that is administrative in nature.

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline (1) — Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the ~~Bulk-Power System~~bulk power system.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the ~~Bulk-Power System~~bulk power system:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline (2) — Consistency within a Reliability Standard

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline (3) — Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) — Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline (5) — Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

The following discussion addresses how the SDT considered FERC's VRF Guidelines 2 through 5. The team did not address Guideline 1 directly because of an apparent conflict between Guidelines 1 and 4. Whereas Guideline 1 identifies a list of topics that encompass nearly all topics within NERC's Reliability Standards and implies that these requirements should be assigned a "High" VRF, Guideline 4 directs assignment of VRFs based on the impact of a specific requirement to the reliability of the system. The SDT believes that Guideline 4 is reflective of the intent of VRFs in the first instance and therefore concentrated its approach on the reliability impact of the requirements.

There are eleven requirements in TOP-001-2. None of the eleven requirements were assigned a "Lower" VRF. Requirements R1, R2, R4, R7, and R11 were assigned a "High" VRF while all of the other requirements were given a "Medium" VRF.

VRF for TOP-001-2, Requirement R1:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements so only one VRF was assigned. Therefore, there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R8) in approved IRO-001-1.1 that is assigned a High VRF. The requirements are viewed as similar since they both refer to complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to comply with a Reliability Directive issued by a Transmission Operator could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. Therefore, this requirement is assigned a High VRF.

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R1 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R2:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R3) in approved TOP-001-1.1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the inability of complying with a directive: IRO-001-1.1 for a directive issued by a Reliability Coordinator and TOP-001-2 for a Reliability Directive issued by a Transmission Operator.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Not informing~~-~~ a Transmission Operator of the inability to perform ~~A~~a Reliability Directive could directly affect the electrical state or the capability of the bulk power system and could lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. Therefore, this requirement is assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R2 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R3:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to informing other reliability entities of known or expected conditions.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to notify other reliability entities of known or expected Emergency conditions could lead to bulk power system instability, separation or ~~cascading~~ Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R3 contains only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R4:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R4 is a new requirement, so there are no comparable requirements in other standards with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to render ~~emergency~~ Emergency assistance could lead to bulk power system instability, separation or ~~cascading~~ Cascading failures. Thus, this requirement meets the criteria for a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R4 has only one objective, therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R5:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R5) in approved TOP-001-1a that is assigned a High VRF. The requirements are viewed as similar since they both refer to the coordination of activities with other reliability entities.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate activities could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. The applicable entities are always responsible for maintaining the reliability of the bulk power system regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate activities will not, by itself, lead to instability, separation, or ~~cascading~~ Cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R5 contains only one objective. Therefore only one VRF was assigned.

VRF for TOP-001-2, Requirement R6:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R6 has been assigned a Medium VRF and is the replacement~~-~~ for proposed TOP-003-1, Requirement R3 which was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. Failure to coordinate outages could directly affect the electrical state or the capability of the bulk power system. However, violation of this requirement is unlikely to lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. The applicable entities are always responsible for maintaining the

reliability of the bulk power system, regardless of the situation. Thus, this requirement meets NERC's criteria for a Medium VRF. Failure to coordinate outages will not, by itself, lead to instability, separation, or ~~cascading~~ Cascading failures

- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2 Requirement R6 contains only one objective. Therefore only one VRF was assigned to the requirement.

VRF for TOP-001-2, Requirement R7:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. There is a similar requirement (Requirement R1) in approved TOP-004-2 that is assigned a High VRF. The requirements are viewed as similar since they both refer to operating within the IROL.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R7 mandates that entities operate within each identified IROL and its associated IROL T_V. By definition, if an entity fails to do so, bulk power system instability, separation, or ~~cascading~~ Cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R7 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R8:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- ~~Bulk power system instability, separation, or cascading failures. Therefore, this requirement was assigned a Medium VRF.~~ FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R8 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R8 is a notification requirement. If the Transmission Operator failed to notify the Reliability Coordinator of a specific System Operating Limit (SOL) that supports local area reliability, the Transmission Operator is still obligated to operate to alleviate the SOL through the proposed TOP-001-2, Requirement R9. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R8 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R9:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R9 is a new requirement, so there are no comparable requirements with which to compare VRFs.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R9 mandates that entities operate within each identified local SOL. Since local SOLs in Requirement R9, by definition, can't cause bulk power system instability, separation, or ~~cascading~~ Cascading this requirement was assigned a Medium VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R9 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R10:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.
- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R10 is a new requirement that was assigned a Medium VRF. When evaluating the VRF to be assigned to this requirement, the SDT took into account that this requirement is an informational item, not the actual action to alleviate the problem. The action is covered in proposed TOP-001-2, Requirements R7 and R9~~ which have High VRFs~~. Therefore, the simple act of failing to notify the Reliability Coordinator, while it may impair the Reliability Coordinator's understanding, does not, in itself, lead to bulk power system instability, separation, or ~~cascading~~ Cascading failures. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R10 mandates that entities notify their Reliability Coordinator of actions taken to alleviate a problem. The action has already been taken as per proposed TOP-001-2, Requirements R7, R9, and R11 and this requirement is a simple notification requirement for informational purposes only. Therefore, bulk power system instability, separation, or ~~cascading~~ Cascading failures are not likely to occur due to a failure to notify the Reliability Coordinator. Therefore, this requirement was assigned a Medium VRF.
- FERC's Guideline 5 - Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R10 addresses a single objective and has a single VRF.

VRF for TOP-001-2, Requirement R11:

- FERC's Guideline 2 — Consistency within a Reliability Standard. The requirement has no sub-requirements; only one VRF was assigned so there is no conflict.

- FERC's Guideline 3 — Consistency among Reliability Standards. TOP-001-2, Requirement R11 is a new requirement, so there are no comparable requirements with which to compare VRFs. However, it is similar to approved TOP-008-1, Requirement R1 which has a High VRF. It is also similar to proposed TOP-001-2, Requirement R7 which has been assigned a High VRF. Therefore, there is consistency among Reliability Standards.
- FERC's Guideline 4 — Consistency with NERC's Definition of a VRF. TOP-001-2, Requirement R11 mandates that entities act or direct others to act to mitigate the magnitude and duration of exceeding an IROL and its associated IROL T_v or SOL identified in Requirement R8. By definition, if an entity fails to do so, bulk power system instability, separation, or ~~cascading~~ Cascading failures are likely to occur. Therefore, this requirement was assigned a High VRF.
- FERC's Guideline 5 — Treatment of Requirements that Co-mingle More Than One Objective. TOP-001-2, Requirement R11 addresses a single objective and has a single VRF.

Justification for Assignment of Violation Severity Levels for TOP-001-2, TOP-002-3, TOP-003-2:

In developing the VSLs for the TOP standard, the SDT anticipated the evidence that would be reviewed during an audit, and developed its VSLs based on the noncompliance an auditor may find during a typical audit. The SDT based its assignment of VSLs on the following NERC criteria:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in TOP-xxx-x meet the FERC Guidelines for assessing VSLs:

Guideline 1: Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2: Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4: Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the “default” for penalty calculations.

VSLs for TOP-001-2 Requirement R1:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R1.	Meets NERC's VSL guidelines – Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved IRO-001-1.1, Requirement R8. That VSL has a Moderate violation for not complying with the Reliability Coordinator's directive for a valid reason but not informing the Reliability Coordinator of this fact. It then goes on to establish a Severe VSL for not complying with the directive. The SDT found little reason to separate out a Moderate VSL for not informing	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		the Transmission Operator. Whether it was for a valid reason or not, the consequences of the Transmission Operator not being aware of the fact that the directive was not being followed are potentially catastrophic. Therefore, the SDT has proposed only a Severe VSL and this VSL I ~~s~~ more stringent than the VSL cited. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R2:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R2.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The most comparable VSL for a similar requirement is for the approved TOP-001-1.1a, Requirement R3. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R3:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R3.	Meets NERC's VSL guidelines – There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSL for a similar requirement is for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R4:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R4.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R5:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R5.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The most comparable VSLs for a similar requirement are for the approved TOP-001-1a, Requirement R5. Those VSLs are also based on failure to notify reliability entities with no Lower or Higher VSL and a Moderate VSL for failure to inform while taking action and the Severe VSL for failure to inform and also not taking action. The SDT has split out the action part of the original requirement (see proposed TOP-001-2, Requirement R11) and this	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
		requirement is now simply about failure to inform. The SDT gradated the VSLs at that point but the new VSLs and the old are equivalent at the Moderate level since the original VSL would have required failure to inform two entities – the Reliability Coordinator and at least one Transmission Operator. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

VSLs for TOP-001-2 Requirement R6:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R6.	Meets NERC's VSL guidelines - There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is similar to proposed TOP-003-1, Requirement R3. The VSL for that requirement is binary. When assigning the VSL for the new requirement, the SDT felt that it was possible to provide a gradual increasing scale for the VSL and assigned the VSLs appropriately.	The proposed VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSLs use the same terminology as used in the associated requirement, and are, therefore, consistent with the requirement.	The VSLs are based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R7:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R7.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is similar to approved TOP-004-2, Requirement R1. That VSL is also based on a single violation and is binary. Thus, the VSLs in the proposed standard do not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R8:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R8.	Meets NERC's VSL guidelines. There is an incremental aspect to the violation and the VSLs follow the guidelines for incremental violations.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R9:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R9.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R10:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R10.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

VSLs for TOP-001-2 Requirement R11:

R#	Compliance with NERC's VSL Guidelines	Guideline 1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	Guideline 2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Guideline 4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations
R11.	Meets NERC's VSL guidelines - Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance.	The proposed requirement is new and there are no comparable VSLs but it is similar to approved TOP-008-1, Requirement R1. That VSL is binary as is the one proposed for this new requirement. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.	The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.	The proposed VSL uses the same terminology as used in the associated requirement, and is, therefore, consistent with the requirement.	The VSL is based on a single violation and not cumulative violations.

		Therefore, it decided that the VSL for this requirement should be binary. Thus, the VSL in the proposed standard does not lower the level of compliance currently required by setting VSLs that are less punitive than those already proposed.			

A. Introduction

1. **Title:** **Operating Personnel Responsibility and Authority**

2. **Number:** PER-001-0.1

3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

5. **Effective Date:** December 10, 2009

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:

M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The job description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.

M1.2 The current job description is readily accessible in the control room environment to all operating personnel.

M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.

M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. **Compliance Monitoring Process**

   Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
0.1	April 15, 2009	Replaced “position” with “job” on M1.1	Errata
0.1	December 10, 2009	Approved by FERC — added effective date	Update

A. Introduction

1. Title: **Reliability Responsibilities and Authorities**

2. Number: TOP-001-1

Purpose: To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

3. Applicability

3.1. Balancing Authorities

3.2. Transmission Operators

3.3. Generator Operators

3.4. Distribution Providers

3.5. Load Serving Entities

4. Effective Date: January 1, 2007

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:

R7.1. For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.2. For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.

R7.3. When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.

R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

C. Measures

M1. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, signed agreements, an authority letter signed by an officer of the company, or other equivalent evidence that will be used to confirm that it has the authority, and has exercised the authority, to alleviate operating emergencies as described in Requirement 1.

M2. If an operating emergency occurs the Transmission Operator that experienced the emergency shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it took immediate actions to alleviate the operating emergency including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc. (Requirement 2)

M3. Each Transmission Operator, Balancing Authority, and Generator Operator shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Reliability Coordinator's reliability directives. If the Transmission Operator, Balancing Authority or Generator Operator did not comply with the directive because it would violate safety, equipment, regulatory or statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Reliability Coordinator of its inability to perform the directive. (Requirement 3)

M4. Each Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity shall have and provide upon request evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it complied with its Transmission Operator's reliability directives. If the Balancing Authority, Generator Operator, Distribution Provider and Load Serving Entity did not comply with the directive because it would violate safety, equipment, regulatory or

statutory requirements, it shall provide evidence such as operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that it immediately informed the Transmission Operator of its inability to perform the directive. (Requirements 3 and 4)

M5. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it informed its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and took actions to avoid, when possible, or to mitigate an emergency. (Requirement 5)

M6. The Transmission Operator, Balancing Authority, and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it rendered assistance to others as requested, provided that the requesting entity had implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements. (Requirement 6)

M7. The Transmission Operator and Generator Operator shall each have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified either their Transmission Operator in the case of the Generator Operator, or other Transmission Operators, and the Reliability Coordinator when it removed Bulk Electric System facilities from service if removing those facilities would burden neighboring systems. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall have the current in-force document to show that it has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area. (Measure 1)

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measures 1 through 7, including evidence of directives issued for Measures 3 and 4.

Each Balancing Authority shall keep 90 days of historical data (evidence) for Measures 3, 4 and 6 including evidence of directives issued for Measures 3 and 4.

Each Generator Operator shall keep 90 days of historical data (evidence) for Measures 3, 4, 6 and 7 including evidence of directives issued for Measures 3 and 4.

Each Distribution Provider and Load-serving Entity shall keep 90 days of historical data (evidence) for Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for a Balancing Authority:

2.1. Level 1: Not applicable.

2.2. Level 2: Not applicable.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not comply with a Reliability Coordinator's or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive (R3)

2.4.2 Did not render emergency assistance to others as requested, in accordance with R6.

3. Levels of Non-Compliance for a Transmission Operator

3.1. Level 1: Not applicable.

3.2. Level 2: Not applicable.

3.3. Level 3: Not applicable.

3.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

3.4.1 Does not have the documented authority to act as specified in R1.

3.4.2 Does not have evidence it acted with the authority specified in R1.

3.4.3 Did not take immediate actions to alleviate operating emergencies as specified in R2.

3.4.4 Did not comply with its Reliability Coordinator's reliability directive or did not immediately inform the Reliability Coordinator of its inability to perform that directive, as specified in R3.

3.4.5 Did not inform its Reliability Coordinator and other potentially affected Transmission Operators of real time or anticipated emergency conditions as specified in R5.

3.4.6 Did not take actions to avoid, when possible, or to mitigate an emergency as specified in R5.

3.4.7 Did not render emergency assistance to others as requested, as specified in R6.

3.4.8 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and removing those facilities burdened a neighbor system.

4. Levels of Non-Compliance for a Generator Operator:

4.1. Level 1: Not applicable.

4.2. Level 2: Not applicable.

4.3. Level 3: Not applicable.

4.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

4.4.1 Did not comply with a Reliability Coordinator or Transmission Operator's reliability directive or did not immediately inform the Reliability Coordinator or Transmission Operator of its inability to perform that directive, as specified in R3.

4.4.2 Did not render all available emergency assistance to others as requested, unless such actions would violate safety, equipment, or regulatory or statutory requirements as specified in R6.

4.4.3 Removed Bulk Electric System facilities from service under conditions other than those specified in R7.1, 7.2, and 7.3, and burdened a neighbor system.

5. Levels of Non-Compliance for a Distribution Provider or Load Serving Entity

5.1. Level 1: Not applicable.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable

5.4. Level 4: Did not comply with a Transmission Operator's reliability directive or immediately inform the Transmission Operator of its inability to perform that directive, as specified in R4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

A. Introduction

1. **Title:** **Normal Operations Planning**

2. **Number:** TOP-002-2a

3. **Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.

4. **Applicability**

   4.1. Balancing Authority.

   4.2. Transmission Operator.

   4.3. Generator Operator.

   4.4. Load Serving Entity.

   4.5. Transmission Service Provider.

5. **Effective Date:** Immediately after approval of applicable regulatory authorities. FERC Approved 12/2/09

B. Requirements

R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.

R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.

R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.

R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.

R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.

R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.

R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.

R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.

R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.

R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:

R14.1. Changes in real and reactive output capabilities. (Retired August 1, 2007)

R14.1. Changes in real output capabilities. (Effective August 1, 2007)

R14.2. Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)

R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).

R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:

R16.1. Changes in transmission facility status.

R16.2. Changes in transmission facility rating.

R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.

R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

M1. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, documented planning procedures, copies of current day plans, copies of seasonal operations plans, or other equivalent evidence that will be used to confirm that it maintained a set of current plans. (Requirement 1 Part 1).

M2. Each Balancing Authority and Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 5, 6, and 10.

M3. Each Balancing Authority shall have and provide upon request evidence that could include, but is not limited to, copies of current day plans or other equivalent evidence that will be used to confirm that its plans address Requirements 7, 8, and 9.

M4. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, its next-day, and current-day Bulk Electric System studies used to determine SOLs or other equivalent evidence that will be used to confirm that its studies reflect current system conditions. (Requirement 11 Part 1)

M5. Each Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that the results of Bulk Electric System studies were made available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator. (Requirement 11 Part 2)

M6. Each Generator Operator shall have and provide upon request evidence that, when requested by either a Transmission Operator or Balancing Authority, it performed a generating real and reactive capability verification and provided the results to the requesting entity in accordance with Requirement 13.

M7. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that without any intentional time delay, it notified its Balancing Authority and Transmission Operator of changes in real and reactive capabilities and AVR status. (Requirement 14)

M8. Each Generator Operator shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, on request, it provided a forecast of expected real power output to assist in operations planning. (Requirement 15)

M9. Each Transmission Operators shall have and provide upon request evidence that could include, but is not limited to, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that, without any intentional time delay, it notified its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics. (Requirement16)

M10. Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider and Load Serving Entity shall have and provide upon request evidence that could include, but is not limited to, a list of interconnected transmission facilities and their line identifiers at each end or other equivalent evidence that will be used to confirm that it used uniform line identifiers when referring to transmission facilities of an interconnected network. (Requirement 18)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 calendar days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

For Measures 1 and 2, each Transmission Operator shall have its current plans and a rolling 6 months of historical records (evidence).

For Measures 1, 2, and 3 each Balancing Authority shall have its current plans and a rolling 6 months of historical records (evidence).

For Measure 4, each Transmission Operator shall keep its current plans (evidence).

For Measures 5 and 9, each Transmission Operator shall keep 90 days of historical data (evidence).

For Measures 6, 7 and 8, each Generator Operator shall keep 90 days of historical data (evidence).

For Measure 10, each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, and Load-serving Entity shall have its current list interconnected transmission facilities and their line identifiers at each end or other equivalent evidence as evidence.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. **Levels of Non-Compliance for Balancing Authorities:**

   2.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

   2.2. **Level 2:** Not applicable.

   2.3. **Level 3:** Not applicable.

   2.4. **Level 4**: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      2.4.1 Did not maintain an updated set of current-day plans as specified in R1.

      2.4.2 Plans did not meet one or more of the requirements specified in R5 through R10.

3. **Levels of Non-Compliance for Transmission Operators**

   3.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

   3.2. **Level 2:** Not applicable.

   3.3. **Level 3:** One or more of Bulk Electric System studies were not made available as specified in R11.

   3.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      3.4.1 Did not maintain an updated set of current-day plans as specified in R1.

      3.4.2 Plans did not meet one or more of the requirements in R5, R6, and R10.

      3.4.3 Studies not updated to reflect current system conditions as specified in R11.

      3.4.4 Did not notify its Balancing Authority and Reliability Coordinator of changes in capabilities and characteristics as specified in R16.

4. **Levels of Non-Compliance for Generator Operators:**

   4.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

   4.2. **Level 2:** Not applicable.

   4.3. **Level 3:** Not applicable.

   4.4. **Level 4:** There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

      4.4.1 Did not verify and provide a generating real and reactive capability verification and provide the results to the requesting entity as specified in R13.

      4.4.2 Did not notify its Balancing Authority and Transmission Operator of changes in capabilities and characteristics as specified in R14.

      4.4.3 Did not provide a forecast of expected real power output to assist in operations planning as specified in R15.

5. **Levels of Non-Compliance for Transmission Service Providers and Load-serving Entities:**

   5.1. **Level 1:** Did not use uniform line identifiers when referring to transmission facilities of an interconnected network as specified in R18.

5.2. Level 2: Not applicable.

5.3. Level 3: Not applicable.

5.4. Level 4: Not applicable.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	June 14, 2007	Fixed typo in R11., (subject to …)	Errata
2a	February 10, 2009	Added Appendix 1 – Interpretation of R11 approved by BOT on February 10, 2009	Interpretation
2a	December 2, 2009	Interpretation of R11 approved by FERC on December 2, 2009	Same Interpretation

Appendix 1

Interpretation of Requirement R11

Requirement Number and Text of Requirement

Requirement R11: The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject to confidentiality requirements), and to its Reliability Coordinator.

Question #1
Is the Transmission Operator required to conduct a "unique" study for each operating day, even when the actual or expected system conditions are identical to other days already studied? In other words, can a study be used for more than one day?

Response to Question #1
Requirement R11 mandates that each Transmission Operator review (i.e., study) the state of its Transmission Operator area both in advance of each day and during each day. Each day must have "a" study that can be applied to it, but it is not necessary to generate a "unique" study for each day. Therefore, it is acceptable for a Transmission Operator to use a particular study for more than one day.

Question #2
Are there specific actions required to implement a "study"? In other words, what constitutes a study?

Response to Question #2
The requirement does not mandate a particular type of review or study. The review or study may be based on complex computer studies or a manual reasonability review of previously existing study results. The requirement is designed to ensure the Transmission Operator maintains sensitivity to what is happening or what is about to happen.

Question #3
Does the term, "to determine SOLs" as used in the first sentence of Requirement R11 mean the "determination of system operating limits" or does it mean the "identification of potential SOL violations?"

Response to Question #3
TOP-002-2 covers real-time and near-real-time studies. Requirement R11 is meant to include both determining new limits and identifying potential "exceedances" of pre-defined SOLs. If system conditions indicate to the Transmission Operator that prior studies and SOLs may be outdated, TOP-002-2 mandates the Transmission Operator to conduct a study to identify SOLs for the new conditions. If the Transmission Operator determines that system conditions do not warrant a new study, the primary purpose of the review is to check that the previously defined (i.e., defined from the current SOLs in use, or the set defined by the planners) SOLs are not expected to be exceeded. As written, the standard provides the Transmission Operator discretion regarding when to look for new SOLs and when to rely on its current set of SOLs.

A. Introduction

1. **Title:** **Planned Outage Coordination**
2. **Number:** TOP-003-1
3. **Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.
4. **Applicability**
   - **4.1.** Generator Operators.
   - **4.2.** Transmission Operators.
   - **4.3.** Balancing Authorities.
   - **4.4.** Reliability Coordinators.
5. **Proposed Effective Date:**

   In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Generator Operators and Transmission Operators shall provide planned outage information.

- **R1.1.** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.
- **R1.2.** Each Transmission Operator shall provide outage information daily to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.
- **R1.3.** Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.

R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators as required.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.

R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

M1. Evidence that the Generator Operator, Transmission Operator, and Balancing Authority reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to "not be taken" because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The Generator Operator failed to provide outage information, in accordance with its Transmission Operators established outage reporting requirements, to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW).
R1.1	N/A	N/A	N/A	The Transmission Operator failed to provide outage information, in accordance with its Reliability Coordinators established outage reporting requirement, to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation.
R1.2	The responsible entity failed to provide the information by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	N/A	N/A	N/A

R#	Lower	Moderate	High	Severe
R1.3	N/A	N/A	N/A	The responsible entity failed to plan or coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators when required.
R2	The responsible entity planned and coordinated scheduled outages of telemetering and control equipment and associated communication channels with its Reliability Coordinator, but failed to coordinate with affected neighboring Transmission Operators, Balancing Authorities, and Generator Operators.	N/A	N/A	The responsible entity failed to plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
R3	N/A	N/A	N/A	The Reliability Coordinator failed to resolve any scheduling of potential reliability conflicts.
R4	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 30 minutes but less than or equal to 35 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 35 minutes but less than or equal to 40 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 40 minutes but less than or equal to 45 minutes.	The Transmission Operator entering an unknown operating state (i.e., any state for which valid operating limits have not been determined), failed to restore operations to respect proven reliable power system limits for more than 45 minutes.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 23, 2011	Order issued by FERC approving TOP-003-1 (approval effective 5/23/11)	

A. Introduction

1. **Title:** **Transmission Operations**

2. **Number:** TOP-004-2

3. **Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.

4. **Applicability:**

   4.1. Transmission Operators

5. **Proposed Effective Date:** Twelve months after BOT adoption of FAC-014.

B. Requirements

R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).

R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.

R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.

R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:

R6.1. Monitoring and controlling voltage levels and real and reactive power flows.

R6.2. Switching transmission elements.

R6.3. Planned outages of transmission elements.

R6.4. Responding to IROL and SOL violations.

C. Measures

M1. Each Transmission Operator that enters an unknown operating state for which valid limits have not been determined, shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it restored operations to respect proven reliable power system limits within 30 minutes as specified in Requirement 4.

M2. Each Transmission Operator shall have and provide upon request current policies and procedures that address the execution and coordination of activities that impact inter- and intra-Regional reliability for each of the topics listed in Requirements 6.1 through 6.6.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data for Measure 1.

Each Transmission Operator shall have current, in-force policies and procedures, as evidence of compliance to Measure 2.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance:

2.1. Level 1: Not applicable.

2.2. Level 2: Did not have formal policies and procedures to address one of the topics listed in R6.1 through R6.4.

2.3. .**Level 3:** Did not have formal policies and procedures to address two of the topics listed in R6.1 through R6.4.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not restore operations to respect proven reliable power system limits within 30 minutes as specified in R4.

2.4.2 Did not have formal policies and procedures to address three or all of the topics listed in R6.1 through R6.4.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Added language from Missing Measures and Compliance Elements adopted by Board of Trustees on November 1, 2006	Revised
2	December 19, 2007	Revised to reflect merging of both sets of changes approved by BOT on November 1, 2006 (Addition of measures and compliance elements and revisions to R3 and R6 with conforming changes made as errata to Levels of Non-compliance)	Revised Errata

A. Introduction

1. **Title:** **Operational Reliability Information**

2. **Number:** TOP-005-2

3. **Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.

4. **Applicability**

   4.1. Transmission Operators.

   4.2. Balancing Authorities.

   4.3. Purchasing Selling Entities.

5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

   In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."

R2. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.

R3. Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

M1. Evidence that the Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

   Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Time Frame

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The ISN data recipient failed to sign the NERC Confidentiality Agreement for "Electric System Reliability Data".
R2	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.
R3	The responsible entity failed to provide any of the data requested by other Balancing Authorities or Transmission Operators.	N/A	N/A	The responsible entity failed to provide all of the data requested by its host Balancing Authority or Transmission Operator.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1		Removed the Reliability Coordinator from the list of responsible functional entities Deleted R1 and R1.1 Modified M1 to omit the reference to the Reliability Coordinator Deleted VSLs for R1 and R1.1	Revised
2	March 23, 2011	Order issued by FERC approving TOP-005-2 (approval effective 5/23/11)	

Attachment 1-TOP-005

Electric System Reliability Data

This Attachment lists the types of data that Balancing Authorities, and Transmission Operators are expected to share with other Balancing Authorities and Transmission Operators.

1. The following information shall be updated at least every ten minutes:

1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:

1.1.1 Status.

1.1.2 MW or ampere loadings.

1.1.3 MVA capability.

1.1.4 Transformer tap and phase angle settings.

1.1.5 Key voltages.

1.2. Generator data.

1.2.1 Status.

1.2.2 MW and MVAR capability.

1.2.3 MW and MVAR net output.

1.2.4 Status of automatic voltage control facilities.

1.3. Operating reserve.

1.3.1 MW reserve available within ten minutes.

1.4. Balancing Authority demand.

1.4.1 Instantaneous.

1.5. Interchange.

1.5.1 Instantaneous actual interchange with each Balancing Authority.

1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.

1.5.3 Interchange Schedules for the next 24 hours.

1.6. Area Control Error and frequency.

1.6.1 Instantaneous area control error.

1.6.2 Clock hour area control error.

1.6.3 System frequency at one or more locations in the Balancing Authority.

2. Other operating information updated as soon as available.

2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.

2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.

2.3. Forecast peak demand for current day and next day.

2.4. Forecast changes in equipment status.

2.5. New facilities in place.

2.6. New or degraded special protection systems.

2.7. Emergency operating procedures in effect.

2.8. Severe weather, fire, or earthquake.

2.9. Multi-site sabotage.

A. Introduction

1. **Title:** **Monitoring System Conditions**

2. **Number:** TOP-006-2

3. **Purpose:** To ensure critical reliability parameters are monitored in real-time.

4. **Applicability**

    4.1. Transmission Operators.

    4.2. Balancing Authorities.

    4.3. Generator Operators.

    4.4. Reliability Coordinators.

5. **Proposed Effective Date:** In those jurisdictions where no regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after BOT adoption.

    In those jurisdictions where regulatory approval is required, the standard shall become effective on the latter of either April 1, 2009 or the first day of the first calendar quarter, three months after applicable regulatory approval.

B. Requirements

R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.

R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.

R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.

R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.

R4. Each Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

C. Measures

M1. The Generator Operator shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Host Balancing Authority and Transmission Operator of all generation resources available for use. (Requirement 1.1)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it informed its Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use. (Requirement 1.2)

M3. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, computer printouts or other equivalent evidence that will be used to confirm that it monitored each of the applicable items listed in Requirement 2.

M4. Each Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, printouts, training documents, description documents or other equivalent evidence that will be used to confirm that it has weather forecasts and past load patterns, available to predict the system's near-term load pattern. (Requirement 4)

M5. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a description of its EMS alarm capability, training documents, or other equivalent evidence that will be used to confirm that important deviations in operating conditions and the need for corrective actions will be brought to the attention of its operators. (Requirement 5)

M6. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, a list of the frequency monitoring points available to the shift-operators or other equivalent evidence that will be used to confirm that it monitors system frequency. (Requirement 7)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Generator Operator shall keep 90 days of historical data (evidence) for Measure 1.

Each Transmission Operator and Balancing Authority shall keep 90 days of historical data (evidence) for Measure 2.

Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have current documents as evidence for Measure 3, 5 and 6.

Each Transmission Operator and Balancing Authority shall have current documents as evidence of compliance to Measure 4.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all supporting compliance data

1.4. Additional Compliance Information

None.

2. Violation Severity Levels:

R#	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity failed to know the status of all generation and transmission resources available for use, even though said information was reported by the Generator Operator, Transmission Operator, or Balancing Authority.
R1.1	N/A	N/A	N/A	The Generator Operator failed to inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
R1.2	N/A	N/A	N/A	The responsible entity failed to inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
R2	N/A	The responsible entity monitors the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, but is not aware of the status of rotating and static reactive resources.	The responsible entity fails to monitor all of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of all rotating and static reactive resources.	The responsible entity fails to monitor any of the applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
R3	The responsible entity failed to provide any of the appropriate technical information concerning protective relays to their operating personnel.	N/A	N/A	The responsible entity failed to provide all of the appropriate technical information concerning protective relays to their operating personnel.

R#	Lower	Moderate	High	Severe
R4	N/A	N/A	The responsible entity has either weather forecasts or past load patterns, available to predict the system's near-term load pattern, but not both.	The responsible entity failed to have both weather forecasts and past load patterns, available to predict the system's near-term load pattern.
R5	N/A	N/A	The responsible entity used monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions, but does not have indication of the need for corrective action.	The responsible entity failed to use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions.
R6	N/A	N/A	N/A	The responsible entity failed to use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.
R7	N/A	N/A	N/A	The responsible entity failed to monitor system frequency.

E. Regional Variances

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2		Modified R4 Modified M4 Modified Data Retention for M4 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
2	October 17, 2008	Adopted by NERC Board of Trustees	
2	March 23, 2011	Order issued by FERC approving TOP-006-2 (approval effective 5/23/11)	

A. Introduction

1. **Title:** Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations

2. **Number:** TOP-007-0

3. **Purpose:**

   This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.

4. **Applicability:**

   4.1. Transmission Operators.

   4.2. Reliability Coordinators.

5. **Effective Date:** April 1, 2005

B. Requirements

R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.

R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.

R3. A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.

R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

C. Measures

M1. Evidence that the Transmission Operator informed the Reliability Coordinator when an IROL or SOL was exceeded and the actions taken to return the system to within limits.

M2. Evidence that the Transmission Operator returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.

M3. Evidence that the Reliability Coordinator evaluated actions and provided direction required to return the system to within limits.

D. Compliance

1. **Compliance Monitoring Process**

   1.1. Compliance Monitoring Responsibility

   The Reliability Coordinator shall report any IROL violation exceeding 30 minutes to the Regional Reliability Organization and NERC within 72 hours. Each Regional Reliability Organization shall report any such violations to NERC via the NERC compliance reporting process. The Reliability Coordinator shall report any SOL violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:

1.1.1. System instability.

1.1.2. Unacceptable system dynamic response or equipment tripping.

1.1.3. Voltage levels in violation of applicable emergency limits.

1.1.4. Loadings on transmission facilities in violation of applicable emergency limits.

1.1.5. Unacceptable loss of load based on regional and/or NERC criteria.

1.2. Compliance Monitoring Period and Reset Timeframe

The reset period is monthly.

1.3. Data Retention

The data retention period is three months.

2. Levels of Non-Compliance

2.1. The Transmission Operator did not inform the Reliability Coordinator of an IROL or an SOL that has become an IROL because of changed system conditions, and the actions they are taking to return the system to within limits, or

2.2. The Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the system to within the IROL within 30 minutes. (See Table 1-TOP-007-0 below.)

2.3. The limit violation was reported to the Reliability Coordinator, who did not provide appropriate direction to the Transmission Operator, resulting in an IROL violation in excess of 30 minutes duration.

Table 1-TOP-007-0 IROL and SOL Reporting Levels of Non-Compliance

Percentage by which IROL or SOL that has become an IROL is exceeded*	Limit exceeded for more than 30 minutes, up to 35 minutes.	Limit exceeded for more than 35 minutes, up to 40 minutes.	Limit exceeded for more than 40 minutes, up to 45 minutes.	Limit exceeded for more than 45 minutes.
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

*Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes).

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata

A. Introduction

1. **Title:** **Response to Transmission Limit Violations**
2. **Number:** TOP-008-1
3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.
4. **Applicability**

   4.1. Transmission Operators.
5. **Effective Date:** January 1, 2007

B. Requirements

R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.

R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.

R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

C. Measures

M1. The Transmission Operator involved in an SOL or IROL violation shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program printouts, or other equivalent evidence that will be used to determine if it took immediate steps to relieve the condition. (Requirement 1)

M2. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings, electronic communications, alarm program print outs, or other equivalent evidence that will be used to determine if it disconnected an overloaded facility in accordance with Requirement 3 Part 1

M3. The Transmission Operator that disconnects an overloaded facility shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it notified its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permitted, otherwise, immediately thereafter. (Requirement 3 Part 2)

M4. The Transmission Operator shall have and provide upon request evidence that could include, but is not limited to, computer facilities documents, computer printouts, training documents,

copies of analysis program results, operator logs or other equivalent evidence that will be used to confirm that it has sufficient information and analysis tools to determine the cause(s) of SOL violations. (Requirement 4 Part 1)

M5. The Transmission Operator that violates an SOL shall have and provide upon request evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to confirm that it used the results of these analyses to immediately mitigate the SOL violation. (Requirement 4 Part 3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring and Reset Time Frame

One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

The Performance-Reset Period shall be 12 months from the last finding of non-compliance.

1.3. Data Retention

Each Transmission Operator shall keep 90 days of historical data (evidence) for Measure 1, 2 and 3.

Each Transmission Operator shall have current documents as evidence of compliance to Measures 4 and 5.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor,

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance data

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance for Transmission Operator

2.1. Level 1: Not applicable.

2.2. Level 2: Disconnected an overloaded facility as specified in R3 but did not notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, or immediately thereafter.

2.3. Level 3: Not applicable.

2.4. Level 4: There shall be a separate Level 4 non-compliance, for every one of the following requirements that is in violation:

2.4.1 Did not take immediate steps to relieve an IROL or SOL violation in accordance with R1.

2.4.2 Did not disconnect an overloaded facility as specified in R3.

2.4.3 Does not have sufficient information and analysis tools to determine the cause(s) of SOL violations. (R4 Part 1)

2.4.4 Did not use the results of analyses to immediately mitigate an SOL violation. (R4 Part 3)

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised

Mapping Document

Project 2007-03 Real-time Operations

Mapping document showing the translation of TOP-001-1 — Reliability Responsibilities and Authorities; TOP-002-2a — Normal Operations Planning; TOP-003-1 — Planned Outage Coordination; TOP-004-2 — Transmission Operations; TOP-005-2 — Operational Reliability Information; TOP-006-2 – Monitoring System Conditions; TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations; TOP-008-1 - Response to Transmission Limit Violations; PRC-001-1 – System Protection Coordination; and PER-001-0 - Operating Personnel Responsibility and Authority.

Standard TOP-001-1 — Reliability Responsibilities and Authorities		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	Deleted	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions, as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the bulk power System have been more clearly laid out in revised standards. (See FERC Order 693a, Paragraph 112.) The requirement is also non-specific, ambiguous, and not performance-oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, which makes this requirement superfluous; and, thus, it can be deleted.

		FERC Order 693a, Paragraph 112: "In response to Avista, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of reliability standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize Reliability Coordinators to issue directives. Under the voluntary reliability scheme in place prior to Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a Reliability Coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies, including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	Proposed TOP-001-2, Requirement R11	Replaced by proposed TOP-001-2, R11: The undefined term 'operating emergencies' is no longer utilized, and the requirement has been made more stringent by not restricting Transmission Operator actions to that undefined condition. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant time frame. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued	Proposed IRO-001-3, Requirements R2, R3 & R4.	Replaced by: IRO-001-3, R2. Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent

by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.		identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-001-3, R3. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall comply with its Reliability Coordinator's direction per Requirement R2, unless the direction per Requirement R2 cannot be implemented or such actions would violate safety, equipment, regulatory or statutory requirements. IRO-001-3, R4. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform, as directed per Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	Proposed TOP-001-2, Requirements R1 & R2	Replaced by proposed: TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each reliability directive issued and identified as such by its Transmission Operator(s), unless such actions would violate safety, equipment, regulatory, or statutory requirements. TOP-001-2, R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified reliability directive issued by that Transmission Operator.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate	Proposed TOP-001-2, Requirement R3 Proposed TOP-001-2, Requirement R11.	Replaced by proposed: TOP-001-2, R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis.

the emergency.		TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant time frame.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	Proposed TOP-001-2, Requirement R4 for the Transmission Operator. Approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 for the Balancing Authority	Replaced by proposed TOP-001-2, R4. TOP-001-2, R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Generator Operator was deleted from this requirement since it can't be contacted directly by others and will only respond to such requests if they were in the form of a reliability directive from its Transmission Operator, which is covered in proposed TOP-001-2, Requirement R1. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 covers the Balancing Authority. So to eliminate a redundancy, the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission Operator, as stated in proposed TOP-001-2, Requirement R1. EOP-001-2b, R1. Balancing Authorities shall have

		operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: R7.1 - For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.2 - For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.3 - When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R5	R7: Replaced by proposed TOP-001-2, R5 for the Transmission Operator. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. R7 – The Generator Operator can't know if their actions will burden neighboring Systems, since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring Systems and is required to act on this information, as per proposed TOP-001-2, R5. R7.1 – Replaced by proposed TOP-001-2, R5 for both the Transmission Operator and the Generator Operator. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. R7.2 - Replaced by proposed TOP-001-2, R5 for the Transmission Operator. After-the-fact notifications have been replaced by the proposed TOP-003-2, R1 and approved IRO-010-1a, since those actions will now be seen through telemetry.

notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.		TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading Outages.
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance, it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	Approved EOP-002-3, Requirement R6. Approved VAR-001-1, Requirement R8. Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirements R1, R8, and R12. Approved IRO-009-1, Requirements R1 and R2. Approved EOP-003-1, Requirement R1.	Real Power Balance and Reactive Power Balance are not defined terms. First sentence – Real Power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance Real Power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – Reactive Power: Replaced by Approved VAR-001-1, Requirement R8 for the Transmission Operator, which covers Reactive Power requirements and the meaning of balancing Reactive Power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding Reactive Power per the NERC Functional Model V5 (see proposed TOP-001-2, Requirement R1) and, therefore, the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding

		Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, the Balancing Authority is not necessary. Replaced by approved VAR-001-1, Requirements R1, R8, and R12 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-1, Requirement R1 for the Transmission Operator and Balancing Authority. EOP-002-3, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. VAR-001-1 R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. VAR-001-1, R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, Load shedding – to maintain System and Interconnection voltages within established limits. VAR-001-1, R12. The Transmission Operator shall direct corrective action, including Load reduction necessary to prevent voltage collapse when reactive resources are insufficient. TOP-001-2, R1. Each Balancing Authority, Generator

		Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. IRO-009-1, R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more operating processes, procedures, or plans that identify actions it shall take, or actions it shall direct others to take (up to and including Load shedding) that can be implemented in time to prevent exceeding those IROLs. IRO-009-1, R2.For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more operating processes, procedures, or plans that identify actions it shall take, or actions it shall direct others to take (up to and including Load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load rather than risk an uncontrolled failure of components or Cascading Outages of the Interconnection.
Standard TOP-002-2a — Normal Operations Planning		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for	Approved BAL-001-0.1a. Approved BAL-002-1.	First sentence – Deleted for Balancing Authority, retained for Transmission Operator. The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and

reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	Approved EOP-002-2.1, Requirement R6. Proposed TOP-002-3, Requirements R1 through R3.	must take action, per approved EOP-002-2.1, Requirement R6 and, thus, the Balancing Authority part of this sentence can be deleted. Retained for Transmission Operator and moved to proposed TOP-002-3, Requirements R1 through R3. This is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator. Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities, as per their certification as NERC registered entities. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing Real Power demand and supply in Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of Load, and because Contingency Reserve activation does not typically apply to the loss of Load, the application of DCS is limited to the loss of supply, and does not apply to the loss of Load. EOP-002-2.1, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. TOP-002-3, R1: Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.

		TOP-002-3, R2: Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. TOP-002-3, R3: Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	Deleted	The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and, as such, this requirement is no longer needed and can be deleted. Functional Model V5: Transmission Operator: The entity responsible for the reliability of its "local" transmission System, and that operates or directs the operations of the transmission Facilities.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	Proposed TOP-003-2. Approved MOD-001-1a, Requirements R1 & R2. Approved MOD-030-2, Requirement R3.	For all but the Transmission Service Provider, moved to proposed TOP-003-2 requires the transfer of any and all required data, regardless of time frame involved. The Transmission Service Provider provisions are already covered in: • Approved MOD-001-1a, Requirement R1: Transmission Operators select transfer capability methodology from approved MOD-028, -029, or -030. • Approved MOD-030-2, Requirement R3: Transmission Operator gives transmission model updated at least once per day to Transmission Service Provider.

		• Approved MOD-001-1a, Requirement R2: Transmission Service Providers use the methodology designated in approved MOD-001-1a, Requirement R1 by the Transmission Operator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. MOD-001-1a, R1. Each Transmission Operator shall select one of the methodologies listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. MOD-030-2, R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [LA1]MOD-001-1a, R2. Each Transmission Service Provider shall calculate ATC or AFC values, as listed below, using[LA2] the methodology or methodologies selected by its Transmission Operator(s).
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator so that normal Interconnection operation will proceed in an orderly and consistent manner.	Proposed TOP-003-2, Requirement R5. Approved IRO-010-1a, Requirement R3.	Proposed TOP-003-2 requires the transfer of any and all required data between and amongst Balancing Authorities and Transmission Operators, regardless of the time frame involved. Data requirements for Reliability Coordinators are covered in approved IRO-010-1a, Requirement R3 making this requirement redundant for Reliability Coordinators, so the Reliability Coordinator has been removed here. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

		specifications for data. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	Approved BAL-001-0.1a. Proposed TOP-003-2, Requirement R4. Proposed TOP-002-3, Requirement R1.	The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built into the Functional Model. Therefore, the Transmission Operator should be developing the plan and passing it down to the Balancing Authority. The Balancing Authority provides any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R5. The part of the requirement dealing with the Transmission Operator has been moved to proposed TOP-002-3, Requirement R1. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing Real Power demand and supply in Real-time. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

		specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in System configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	Approved BAL-002-1, Requirements R2 – R4. Proposed TOP-003-2, Requirement R5. Proposed TOP-002-3, Requirement R1	The part of this requirement dealing with the Balancing Authority is replaced by approved BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R4. The part of the requirement dealing with the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. The n-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning. The SDT does not believe that there is a need for the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards.

		As stated in the NERC Functional Model V5: " the Balancing Authority's mission is to maintain the balance between Loads and resources in Real-time within its Balancing Authority Area by keeping its actual Interchange equal to its scheduled Interchange and meeting its frequency bias obligation." To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and approved BAL-002-1), Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any System condition. Balancing Authorities are not responsible for the operation of the transmission System. The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview and, as such, has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding Load, generation and Interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or Load shedding). If the Balancing Authorities' actions do not resolve the transmission issues, it is the Transmission Operators' or Reliability Coordinators' responsibility to direct alternative actions. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: BAL-002-1, R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. BAL-002-1, R4. Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator,

		Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. FAC-010-2.1, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-011-2, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-014-2, Purpose. To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing Real Power demand and supply in Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of Load and because Contingency

		Reserve activation does not typically apply to the loss of Load, the application of DCS is limited to the loss of supply and does not apply to the loss of Load.
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	Approved BAL-002-1, Requirement R2. Proposed TOP-002-3, Requirement R1.	The Balancing Authority is required to always plan to meet and recover from Contingency events, as stated in approved BAL-002-1, Requirement R2 and, therefore, this requirement is redundant and can be deleted, as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and are replaced by proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations, since any deliverability problems will appear as limit violations in the analysis. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirement R1. Proposed TOP-002-3, Requirement R1	The Balancing Authority must be told by the Transmission Operator to take actions regarding Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted, as all elements of the requirement are now covered in other standards. Voltage and Reactive Power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is replaced by proposed TOP-002-3, Requirement

		R1 since any deliverability problems will appear as limit violations in the analysis. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	Approved INT-003-2, Requirement R1.	Replaced by approved INT-003-2, R1. INT-003-2, R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Deleted for Balancing Authority. Proposed TOP-002-3, Requirements R1 & R2.	Balancing Authority - The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary, and, thus, this requirement should never have been applicable to the Balancing Authority. SOLs and IROLs are limits for which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations.

		As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between Loads and resources in Real-time within its Balancing Authority Area by keeping its actual Interchange equal to its scheduled Interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the bulk power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. Transmission Operator – replaced by proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs). TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. TOP-002-3, R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability in its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall	Approved FAC-011-2. Approved FAC-014-2.	First sentence – Replaced by FAC-011-2 and FAC-014-2 where SOLs are determined. FAC-011-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	Proposed TOP-002-3, Requirements R1 & R3.	FAC-014-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. Second sentence – Replaced by approved FAC-014-2, R2 & R5.1. FAC-014-2, R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2, R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. Third sentence – Replaced by proposed TOP-002-3. 'update… as necessary' is ambiguous and the SDT believes that proposed TOP-002-3 is a better solution. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-002-3, R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total	Approved MOD-028-1, Requirement R6.1. Approved MOD-029-1a, Requirement R3. Approved MOD-	Replaced by approved MOD-028-1, Requirement R6.1, MOD-029-1a, Requirement R3, and MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included.

Transfer Capability and Available Transfer Capability calculation processes.	30-2 Requirement R2.4.	MOD-028-1, R6.1,Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing Load within the source Balancing Authority area and decreasing generation and/or increasing Load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's System, or A SOL is reached on any other adjacent System in the Transmission model that is not on the study path and the distribution factor is 5% or greater. MOD-029-1a, R3, Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. MOD-030-2, R2.4, Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	Proposed MOD-25-2, Requirement R1 Proposed TOP-003-2, Requirement R5	Replaced by proposed MOD-025-2, R1. MOD-025-2, R1: Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the

		data is recorded to its Transmission Planner. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics; including but not limited to: 14.1 - Changes in real and reactive output capabilities. (Retired August 1, 2007) 14.2 - Changes in real output capabilities. (Effective August 1, 2007) 14.3 - Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: 16.1	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.

- Changes in transmission facility status. 16.2 - Changes in transmission facility rating		
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	Deleted	This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a System reliability issue. This is an administrative item, as seen in the measure, which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities, and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	Deleted	This is part of an entity's certification and is no longer required in standards. Furthermore, accuracy is a relative term that would be difficult to measure and assess compliance with. What is accurate? All calculated line flows are within 5% of actual flows? What if 14,999 lines out of 15,000 had calculated line flows within 5% and the 15,000th had a 6% error? Do we now call the model inaccurate and not rely on the results? How do you define actual flows when meters have accuracy errors, as well (i.e., no perfect meter exists)?
Standard TOP-003-1 — Planned Outage Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment

R1. Generator Operators and Transmission Operators shall provide planned outage information. 1.1 - Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. 1.2 - Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. 1.3 - Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	Proposed TOP-003-2, Requirements R1 & R2	Replaced by proposed TOP-003-2, Requirements R1 & R2. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring.
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R1 Proposed TOP-003-	Replaced by: proposed TOP-001-2, Requirement R5 which requires the Transmission Operator to coordinate actions while proposed TOP-003-2, Requirement R1 requires the Transmission Operator to identify the data it needs from the Balancing Authority to coordinate outages of voltage regulation equipment. Further, proposed TOP-003-2,

generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators, as required.	2, Requirement R5	Requirement R5 requires the Balancing Authority to provide the data to the Transmission Operator that the Transmission Operator identified it needs. TOP-001-2, R5: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations, known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-003-2, R1: Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R5: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	Proposed TOP-001-2, Requirement R6	Moved to proposed TOP-001-2, Requirement R6 TOP-001-2, R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC-registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	Proposed IRO-001-3, R2 Proposed IRO-005-4, R1	Moved to the proposed IRO-001-3, Requirements R3 and proposed IRO-005-4, Requirement R1 which gives the Reliability Coordinator the authority to resolve the conflict. IRO-001-3, R2: Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability

		Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-005-4, R1: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.
Standard TOP-004-2 — Transmission Operations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	Proposed TOP-001-2, Requirements R7and R9	Moved to proposed TOP-001-2, Requirements R7and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL)

		identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. These requirements are not limited by single or multiple Contingencies, but are based solely on identified IROLs (and selected SOLs), regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator. FAC-011-02 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. FAC-014-2, R6 requires the Planning Coordinator to identify the subset of multiple Contingencies from TPL-003 which result in stability limits and to provide this list to the Reliability Coordinators. FAC-011-2, R3.3 requires the Reliability Coordinator to include in their SOL methodology a process for determining which of the stability limits associated with multiple Contingencies are used to establish SOLs. FAC-014-2, R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. FAC-014-2, R1 requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area, while FAC-014-2, R2 also requires the TOP to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. FAC-011-2, R1, The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

		FAC-011-2, R3, The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.3. A process for determining which of the stability limits associated with the list of multiple Contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon, given the actual or expected System conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple Contingencies. FAC-014-2, R1, The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. FAC-014-2, R2, The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2 R6, The Planning Authority shall identify the subset of multiple Contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1. The Planning Authority shall provide this list of multiple Contingencies and the associated stability limits to the Reliability Coordinators that monitor the Facilities associated with these Contingencies and limits. R6.2. If the Planning Authority does not identify any stability-related multiple Contingencies, the

		Planning Authority shall so notify the Reliability Coordinator. TOP-001-2, R7: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	Proposed TOP-001-2, Requirements R7 and R9 Approved EOP-006-2	The SDT has determined a better way to handle such a situation is to treat it like an IROL or restoration scenario, and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is replaced by proposed TOP-001-2, Requirements R7 and R9 and the approved EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power System. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. EOP-006-2, Purpose: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
R5. Each Transmission Operator shall make every effort to remain connected to the	Deleted	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability

Interconnection. If the Transmission Operator determines that by remaining interconnected it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.		Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is a moot point under the Functional Model definitions and can be deleted.
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: 6.1 - Monitoring and controlling voltage levels and real and reactive power flows. 6.2 - Switching transmission elements. 6.3 - Planned outages of transmission elements. 6.4 - Responding to IROL and SOL violations.	Proposed TOP-001-2 Approved VAR-001-1, Requirement R1 Proposed TOP-001-2, Requirements R7 and R9 ProposedTOP-001-2, Requirement R5 Proposed TOP-001-2, Requirement R11	The first sentence has been superseded by the NERC Reliability Standards, taken as a whole. Examples of such would be the proposed TOP-001-2. The second sentence was replaced as follows: R6.1 is duplicative of approved VAR-001-1, Requirement R1 for Reactive. Real Power flows are covered in proposed TOP-001-2, Requirements R7 and R9. R6.2 is covered in proposed TOP-001-2, Requirement R5. R6.3 – moved to proposedTOP-001-2, Requirement R5. R6.4 – moved to proposed TOP-001-2, Requirement R11. TOP-001-2, Purpose: To prevent instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

		TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard TOP-005-2 — Operational Reliability Information		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area. 1.1 - Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any	Approved IRO-010-1a, Requirement R3	Moved to approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.

additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.		
R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Deleted	Confidentiality is not a reliability issue, but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.
R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R4. Each Purchasing-Selling Entity shall provide information, as requested by its Host Balancing Authorities and Transmission Operators, to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted	Deleted as redundant to NAESB standard –All operating data that a Purchasing Selling Entity has, that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-2 – Monitoring System Conditions		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. 1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. 1.2 - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	R1 & R1.1 are replaced by proposed TOP-003-2, Requirement R1. R1.2 – replaced by approved IRO-010-1a, Requirement R3. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3. Approved BAL-005-0.1b. Proposed TOP-001-2, Requirement R10. Approved IRO-008-1, Requirement R2.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-

		time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading outages. The act of monitoring is un-measureable. Entities will be in violation of other standards if they don't perform adequate monitoring. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs, and approved IRO-008-1, Requirement R2 for Real-time assessments every 30 minutes for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

		TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading outages.
R4. Each Transmission Operator and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading outages.
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to	Deleted	Deleted as this is covered in the certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs; approved IRO-008-1, Requirement R2

indicate, if appropriate, the need for corrective action.		for Real-time assessments every 30 minutes for Reliability Coordinators BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R7 for Transmission Operator avoiding IROLs. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, Requirement R2 for Transmission Operator avoiding underfrequency; approved EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. EOP-003-1, R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic Load shedding for underfrequency or undervoltage conditions. EOP-006-2, R8. The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization.
Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded, and the actions being taken to return the system to within limits.	Proposed TOP-001-2, Requirement R10	Moved to proposed TOP-001-2, Requirement R10. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.

R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	Proposed TOP-001-2, Requirement R11	Moved to proposed TOP-001-2, Requirement R11. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. A Transmission Operator shall take all appropriate actions, up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	Approved EOP-003-1, Requirements R1 and in proposed EOP-003-2, Requirement R1	Replaced by approved EOP-003-1, Requirements R1. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load rather than risk an uncontrolled failure of components or Cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	Approved IRO-008-1, Requirement R3	Replaced by approved IRO-008-1, Requirement R3. IRO-008-1, R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.
Standard TOP-008-1 - Response to Transmission Limit Violations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	Approved EOP-003-1, Requirements R1 and in proposed EOP-003-2, Requirement R1 Proposed TOP-001-2, Requirement R11	Replaced by approved EOP-003-1, Requirements R1 and proposed TOP-001-2, Requirement R11. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load, rather than risk an uncontrolled failure of components or Cascading Outages of the Interconnection. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement

		R8.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	Proposed TOP-001-2, Requirements R7 and R9 Approved IRO-009-1, Requirement R5	First sentence – Replaced by proposed TOP-001-2, Requirements R7 and R9. Second sentence – Replaced by approved IRO-009-1, Requirement R5 for the Reliability Coordinator who is now responsible for such matters. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. IRO-009-1, R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	Deleted	Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other reliability standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted	Proposed TOP-003-2, Requirement R1 Proposed TOP-002-3, Requirement R1	Data piece is replaced by proposed TOP-003-2, Requirement R1. Analysis tools are covered in the certification process for core capabilities and, therefore, are not needed

in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	Proposed TOP-001-2, Requirement R7 Proposed TOP-001-2, Requirement R11	here. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Replaced by proposed TOP-002-3, Requirement R1 for analysis. Replaced by proposed TOP-001-2, Requirement R7 for real-time analysis required for IROL mitigation. Proposed TOP-001-2, Requirement R11 covers mitigation of limit violations. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard PER-001-0 - Operating Personnel Responsibility and Authority		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable	Deleted	In FERC Order 693a, Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of reliability standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and

operation of the Bulk Electric System.		Balancing Authorities and that makes this requirement superfluous and, thus, it can be deleted. FERC Order 693a, Paragraph 112: In response to Avista, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of reliability standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a Reliability Coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, these are vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
Standard PRC-001-1 – System Protection Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others: R5.1. Each Generator Operator	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems. R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.		specifications for data.
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

Mapping Document

Project 2007-03 Real-time Operations

Mapping document showing the translation of TOP-001-1 — Reliability Responsibilities and Authorities; TOP-002-2a — Normal Operations Planning; TOP-003-1 — Planned Outage Coordination; TOP-004-2 — Transmission Operations; TOP-005-2 — Operational Reliability Information; TOP-006-2 – Monitoring System Conditions; TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations; TOP-008-1 - Response to Transmission Limit Violations; PRC-001-1 – System Protection Coordination; and PER-001-0 - Operating Personnel Responsibility and Authority.

Standard TOP-001-1 — Reliability Responsibilities and Authorities		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	Deleted	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions, as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the bulk power ~~system~~System have been more clearly laid out in revised standards. (See FERC Order 693a, ~~paragraph~~ Paragraph 112.) The requirement is also non-specific, ambiguous, and not performance~~-~~oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power ~~system~~System is not adversely affected by the deletion of this requirement. In FERC Order 693a, ~~paragraph~~ Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities~~, —~~, which makes this requirement superfluous~~,~~; and, thus, it can be

		deleted. FERC Order 693a, ~~paragraph~~Paragraph 112: “In response to Avista, the Commission clarifies that a ~~reliability~~ Reliability ~~coordinator’s~~ Coordinator’s authority to issue directives arises out of the Commission’s approval of ~~Reliability~~ reliability ~~Standards~~ standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize ~~reliability~~ Reliability ~~coordinators~~ Coordinators to issue directives. Under the voluntary reliability scheme in place prior to ~~section~~ Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a ~~reliability~~ Reliability ~~coordinator’s~~ Coordinator’s directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies, including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	Proposed TOP-001-2, Requirement R11	Replaced by proposed TOP-001-2, R11: The undefined term ‘operating emergencies’ is no longer utilized, and the requirement has been made more stringent by not restricting Transmission Operator actions to that undefined condition. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant time frame. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL’s T_v, or of an SOL identified in Requirement R8.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator,	Proposed IRO-001-3, Requirements R2, R3 & R4.	Replaced by: IRO-001-3, R2. Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators,

and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.		Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-001-3, R3. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall comply with its Reliability Coordinator's direction per Requirement R2, unless the direction per Requirement R2 cannot be implemented or such actions would violate safety, equipment, regulatory or statutory requirements. IRO-001-3, R4. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall inform its Reliability Coordinator- upon recognition of its inability to perform, as directed per Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	Proposed TOP-001-2, Requirements R1 & R2	Replaced by proposed: TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each ~~Reliability~~ reliability ~~Directive~~ directive issued and identified as such by its Transmission Operator(s), unless such actions would violate safety, equipment, regulatory, or statutory requirements. TOP-001-2, R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified ~~Reliability~~ reliability ~~Directive~~ directive issued by that Transmission Operator.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or	Proposed TOP-001-2, Requirement R3 Proposed TOP-001-2, Requirement	Replaced by proposed: TOP-001-2, R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected

anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.	R11.	by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant ~~timeframe~~time frame.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	Proposed TOP-001-2, Requirement R4 for the Transmission Operator. Approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 for the Balancing Authority	Replaced by proposed TOP-001-2, R4. TOP-001-2, R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Generator Operator was deleted from this requirement since it can't be contacted directly by others and will only respond to such requests if they were in the form of a ~~Reliability~~ reliability ~~Directive~~ directive from its Transmission Operator, which is covered in proposed TOP-001-2, Requirement R1. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 covers the Balancing Authority. ~~s~~So to eliminate a redundancy, the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission

		Operator, as stated in proposed TOP-001-2, Requirement R1. EOP-001-2b, R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: R7.1 - For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.2 - For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.3 - When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R5	R7: Replaced by proposed TOP-001-2, R5 for the Transmission Operator. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. R7 – The Generator Operator can't know if their actions will burden neighboring ~~system~~Systems, since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring ~~system~~Systems and is required to act on this information, as per proposed TOP-001-2, R5. R7.1 – Replaced by proposed TOP-001-2, R5 for both the Transmission Operator and the Generator Operator. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. R7.2 - Replaced by proposed TOP-001-2, R5 for the Transmission Operator.

damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.		After-~~-~~the-~~-~~fact notifications have been replaced by the proposed TOP-003-2, R1 and approved IRO-010-1a, since those actions will now be seen through telemetry. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and ~~cascading~~ Cascading ~~outages~~Outages.
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance, it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	Approved EOP-002-3, Requirement R6. Approved VAR-001-1, Requirement R8. Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirements R1, R8, and R12. Approved IRO-009-1, Requirements R1 and R2. Approved EOP-003-1, Requirement R1.	Real Power Balance and Reactive Power Balance are not defined terms. First sentence – ~~real power~~Real Power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance ~~real~~ Real ~~power~~ Power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – ~~reactive~~ Reactive ~~power~~Power: Replaced by Approved VAR-001-1, Requirement R8 for the Transmission Operator, which covers ~~reactive power~~Reactive Power requirements and the meaning of balancing ~~reactive power~~Reactive Power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding ~~reactive power~~Reactive Power per the NERC Functional Model V5 (see proposed TOP-001-2, Requirement R1) and, therefore, the Balancing

		Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding ~~reactive power~~Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, the Balancing Authority is not necessary. Replaced by approved VAR-001-1, Requirements R1, R8, and R12 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-1, Requirement R1 for the Transmission Operator and Balancing Authority. EOP-002-3, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. VAR-001-1 R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. VAR-001-1, R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, ~~load~~Load shedding – to maintain ~~system~~System and Interconnection voltages within established limits.

		VAR-001-1, R12. The Transmission Operator shall direct corrective action, including ~~load~~Load reduction ~~,~~ ~~necessary to~~necessary to prevent voltage collapse when reactive resources are insufficient. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. IRO-009-1, R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more ~~Operating~~ operating ~~Processes~~processes, ~~Procedures~~procedures, or ~~Plans~~ plans that identify actions it shall take, or actions it shall direct others to take (up to and including ~~load~~Load shedding) that can be implemented in time to prevent exceeding those IROLs. IRO-009-1, R2.For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more ~~Operating~~ operating ~~Processes~~processes, ~~Procedures~~procedures, or ~~Plans~~ plans that identify actions it shall take, or actions it shall direct others to take (up to and including ~~load~~Load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer ~~load~~Load rather than risk an uncontrolled failure of components or ~~cascading~~ Cascading ~~outages~~ Outages of the Interconnection.

Standard TOP-002-2a — Normal Operations Planning		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	Approved BAL-001-0.1a. Approved BAL-002-1. Approved EOP-002-2.1, Requirement R6. Proposed TOP-002-3, Requirements R1 through R3.	First sentence – Deleted for Balancing Authority, retained for Transmission Operator. The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and must take action, per approved EOP-002-2.1, Requirement R6 and, thus, the Balancing Authority part of this sentence can be deleted. Retained for Transmission Operator and moved to proposed TOP-002-3, Requirements R1 through R3. This is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator. Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities, as per their certification as NERC registered entities. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing ~~real power~~Real Power demand and supply in ~~real~~Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of ~~load~~Load, and because Contingency Reserve activation does not typically apply to the loss of ~~load~~Load, the application of DCS is limited to the loss of supply, and does not apply to the loss of ~~load~~Load. EOP-002-2.1, R6. If the Balancing Authority cannot comply with the Control Performance and

		Disturbance Control Standards, then it shall immediately implement remedies to do so. TOP-002-3, R1: Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. TOP-002-3, R2: Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. TOP-002-3, R3: Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	Deleted	The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and, as such, this requirement is no longer needed and can be deleted. Functional Model V5: Transmission Operator: The entity responsible for the reliability of its “local” transmission ~~system~~System, and that operates or directs the operations of the transmission ~~facilities~~Facilities.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-	Proposed TOP-003-2. Approved MOD-	For all but the Transmission Service Provider, moved to proposed TOP-003-2 requires the transfer of any and all required data, regardless of ~~timeframe~~time frame involved.

day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	001-1a, Requirements R1 & R2. Approved MOD-030-2, Requirement R3.	The Transmission Service Provider provisions are already covered in: • Approved MOD-001-1a, Requirement R1: Transmission Operators select transfer capability methodology from approved MOD-028, -029, or -030. • Approved MOD-030-2, Requirement R3: Transmission Operator gives transmission model updated at least once per day to Transmission Service Provider. • Approved MOD-001-1a, Requirement R2: Transmission Service Providers use the methodology designated in approved MOD-001-1a, Requirement R1 by the Transmission Operator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. MOD-001-1a, R1. Each Transmission Operator shall select one of the methodologies~~1~~ listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. MOD-030-2, R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [LA1]MOD-001-1a, R2. Each Transmission Service Provider shall calculate ATC or AFC values, as listed below, using[LA2] the methodology or methodologies selected by its Transmission Operator(s).
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-	Proposed TOP-003-2, Requirement R5. Approved IRO-010-	Proposed TOP-003-2 requires the transfer of any and all required data between and amongst Balancing Authorities and Transmission Operators, regardless of the ~~timeframe~~time frame involved.

day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.	1a, Requirement R3.	Data requirements for Reliability Coordinators are covered in approved IRO-010-1a, Requirement R3 making this requirement redundant for Reliability Coordinators, so the Reliability Coordinator has been removed here. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	Approved BAL-001-0.1a. Proposed TOP-003-2, Requirement R4. Proposed TOP-002-3, Requirement R1.	The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built into the Functional Model. Therefore, the Transmission Operator should be developing the plan and passing it down to the Balancing Authority. The Balancing Authority provides any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R5. The part of the requirement dealing with the Transmission Operator has been moved to proposed

		TOP-002-3, Requirement R1. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing ~~real power~~Real Power demand and supply in ~~real~~Real-time. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in System configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	Approved BAL-002-1, Requirements R2 – R4. Proposed TOP-003-2, Requirement R5. Proposed TOP-002-3, Requirement R1	The part of this requirement dealing with the Balancing Authority is replaced by approved ~~BAL-002-0 and proposed~~ BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R4.

		The part of the requirement dealing with the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. The n-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning. The SDT does not believe that there is a need for the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards. As stated in the NERC Functional Model V5: " the Balancing Authority's mission is to maintain the balance between ~~load~~Loads and resources in ~~real time~~Real-time within its Balancing Authority Area by keeping its actual ~~interchange~~Interchange equal to its scheduled ~~interchange~~Interchange and meeting its frequency bias obligation." To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and ~~BAL-002-0 (and the proposed~~ approved BAL-002-1), Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any ~~system~~System condition. Balancing Authorities are not responsible for the operation of the transmission ~~system~~System. The Transmission Operator is responsible for the ~~real~~Real-time operating reliability of the transmission assets under its purview~~,~~ and, as such, has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding ~~load~~Load, generation and ~~interchange~~Interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or ~~load~~Load shedding). If the Balancing Authorities' actions do not resolve the transmission issues, it is the Transmission Operators' or Reliability Coordinators' responsibility to direct alternative actions.

		BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: BAL-002-1, R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. BAL-002-1, R4. Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. FAC-010-2.1, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-011-2, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-014-2, Purpose. To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are

		determined based on an established methodology or methodologies. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing ~~real power~~Real Power demand and supply in ~~real~~Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of ~~load~~Load and because Contingency Reserve activation does not typically apply to the loss of ~~load~~Load, the application of DCS is limited to the loss of supply and does not apply to the loss of ~~load~~Load.
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	Approved BAL-002-1, Requirement R2. Proposed TOP-002-3, Requirement R1.	The Balancing Authority is required to always plan to meet and recover from Contingency events, as stated in approved BAL-002-1, Requirement R2 and, therefore, this requirement is redundant and can be deleted, as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and are replaced by proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations, since any deliverability problems will appear as limit violations in the analysis. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next

		day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirement R1. Proposed TOP-002-3, Requirement R1	The Balancing Authority must be told by the Transmission Operator to take actions regarding ~~reactive power~~Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted, as all elements of the requirement are now covered in other standards. Voltage and ~~reactive power~~Reactive Power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is replaced by proposed TOP-002-3, Requirement R1 since any deliverability problems will appear as limit violations in the analysis. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during

		anticipated normal and Contingency event conditions.
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	Approved INT-003-2, Requirement R1.	Replaced by approved INT-003-2, R1. INT-003-2, R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Deleted for Balancing Authority. Proposed TOP-002-3, Requirements R1 & R2.	Balancing Authority - The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary, and, thus, this requirement should never have been applicable to the Balancing Authority. SOLs and IROLs are limits for which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations. As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between ~~load~~Loads and resources in ~~real time~~Real-time within its Balancing Authority Area by keeping its actual ~~interchange~~Interchange equal to its scheduled ~~interchange~~Interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the bulk power ~~system~~System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. Transmission Operator – replaced by proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs). TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during

		anticipated normal and Contingency event conditions. TOP-002-3, R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability in its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	Approved FAC-011-2. Approved FAC-014-2. Proposed TOP-002-3, Requirements R1 & R3.	First sentence – Replaced by FAC-011-2 and FAC-014-2 where SOLs are determined. FAC-011-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-014-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. Second sentence – Replaced by approved FAC-014-2, R2 & R5.1. FAC-014-2, R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2, R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. Third sentence – Replaced by proposed TOP-002-3.

		'update… as necessary' is ambiguous and the SDT believes that proposed TOP-002-3 is a better solution. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-002-3, R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total Transfer Capability and Available Transfer Capability calculation processes.	Approved MOD-028-1, Requirement R6.1. Approved MOD-029-1a, Requirement R3. Approved MOD-30-2 Requirement R2.4.	Replaced by approved MOD-028-1, Requirement R6.1, MOD-029-1a, Requirement R3, and MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included. MOD-028-1, R6.1,Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing ~~load~~Load within the source Balancing Authority area and decreasing generation and/or increasing ~~load~~Load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's ~~system~~System, or A SOL is reached on any other adjacent ~~system~~System in the Transmission model that is not on the study path and the distribution factor is 5% or greater. MOD-029-1a, R3, Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. MOD-030-2, R2.4, Establish the TFC of each of the defined Flowgates as equal to:

		For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	Proposed MOD-25-2, Requirement R1 Proposed TOP-003-2, Requirement R5	Replaced by proposed MOD-025-2, R1. MOD-025-2, R1: Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the data is recorded to its Transmission Planner. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, ~~Interchange~~Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics; including but not limited to: 14.1 - Changes in real and reactive output capabilities. (Retired August 1, 2007) 14.2 - Changes in real output capabilities. (Effective August 1, 2007) 14.3 - Automatic Voltage Regulator status and mode setting. (Retired August 1,	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

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R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: 16.1 - Changes in transmission facility status. 16.2 - Changes in transmission facility rating	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	Deleted	This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a ~~system~~System reliability issue. This is an administrative item, as seen in the measure, which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators

		as part of their normal responsibilities, and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	Deleted	This is part of an entity's certification and is no longer required in standards. Furthermore, accuracy is a relative term that would be difficult to measure and assess compliance with. What is accurate? All calculated line flows are within 5% of actual flows? What if 14,999 lines out of 15,000 had calculated line flows within 5% and the 15,000th had a 6% error? Do we now call the model inaccurate and not rely on the results? How do you ~~even~~ define actual flows when meters have accuracy errors, as well (i.e., no perfect meter exists)?
Standard TOP-003-1 — Planned Outage Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Generator Operators and Transmission Operators shall provide planned outage information. 1.1 - Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. 1.2 - Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50	Proposed TOP-003-2, Requirements R1 & R2	Replaced by proposed TOP-003-2, Requirements R1 & R2. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring.

MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. 1.3 - Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.		
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators, as required.	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R1 Proposed TOP-003-2, Requirement R5	Replaced by: proposed TOP-001-2, Requirement R5 which requires the Transmission Operator to coordinate actions while proposed TOP-003-2, Requirement R1 requires the Transmission Operator to identify the data it needs from the Balancing Authority to coordinate outages of voltage regulation equipment. Further, proposed TOP-003-2, Requirement R5 requires the Balancing Authority to provide the data to the Transmission Operator that the Transmission Operator identified it needs. TOP-001-2, R5: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations, known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-003-2, R1: Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R5: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data

		specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	Proposed TOP-001-2, Requirement R6	Moved to proposed TOP-001-2, Requirement R6 TOP-001-2, R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC--registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	Proposed IRO-001-3, R2 Proposed IRO-005-4, R1	Moved to the proposed IRO-001-3, Requirements R3 and proposed IRO-005-4, Requirement R1 which gives the Reliability Coordinator the authority to resolve the conflict. IRO-001-3, R2: Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-005-4, R1: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.
Standard TOP-004-2 — Transmission Operations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. TOP-001-2, R7. Each Transmission Operator shall not

System Operating Limits (SOLs).		operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	Proposed TOP-001-2, Requirements R7and R9	Moved to proposed TOP-001-2, Requirements R7and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. These requirements are not limited by single or multiple Contingencies, but are based solely on identified IROLs (and selected SOLs), regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator. FAC-011-02 and FAC-014-2 work collectively to establish how multiple ~~contingencies~~ Contingencies are considered in IROLs and SOLs. FAC-014-2, R6 requires the Planning Coordinator to identify the subset of multiple ~~contingencies~~ Contingencies from TPL-003 which result in stability limits and to provide this list to the Reliability Coordinators. FAC-011-2, R3.3 requires the Reliability Coordinator to include in their SOL methodology a process for determining which of the stability limits associated with multiple ~~contingencies~~ Contingencies are used to

		establish SOLs. FAC-014-2, R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. FAC-014-2, R1 requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area, while FAC-014-2, R2 also requires the TOP to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. FAC-011-2, R1, The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs. FAC-011-2, R3, The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.3. A process for determining which of the stability limits associated with the list of multiple ~~contingencies~~ Contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon, given the actual or expected ~~system~~System conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple ~~contingencies~~Contingencies. FAC-014-2, R1, The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.

		FAC-014-2, R2, The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2 R6, The Planning Authority shall identify the subset of multiple ~~contingencies~~ Contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1. The Planning Authority shall provide this list of multiple ~~contingencies~~ Contingencies and the associated stability limits to the Reliability Coordinators that monitor the ~~facilities~~Facilities associated with these ~~contingencies~~ Contingencies and limits. R6.2. If the Planning Authority does not identify any stability-related multiple ~~contingencies~~Contingencies, the Planning Authority shall so notify the Reliability Coordinator. TOP-001-2, R7: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be	Proposed TOP-001-2, Requirements R7 and R9 Approved EOP-	The SDT has determined a better way to handle such a situation is to treat it like an IROL or restoration scenario, and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is replaced by proposed TOP-001-2,

considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	006-2	Requirements R7 and R9 and the approved EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power ~~system~~System. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. EOP-006-2, Purpose: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
R5. Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected~~,~~ it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.	Deleted	Normally, ~~T~~the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is a moot point under the Functional Model definitions and can be deleted.
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that	Proposed TOP-001-2 Approved VAR-001-1, Requirement R1 Proposed TOP-001-2, Requirements R7 and R9	The first sentence has been superseded by the NERC Reliability Standards, taken as a whole. Examples of such would be the proposed TOP-001-2. The second sentence was replaced as follows: R6.1 is duplicative of approved VAR-001-1, Requirement R1 for ~~reactive~~Reactive. ~~Real power~~Real Power flows are covered in proposed TOP-001-2, Requirements R7 and R9.

impact inter- and intra-Regional reliability, including: 6.1 - Monitoring and controlling voltage levels and real and reactive power flows. 6.2 - Switching transmission elements. 6.3 - Planned outages of transmission elements. 6.4 - Responding to IROL and SOL violations.	ProposedTOP-001-2, Requirement R5 Proposed TOP-001-2, Requirement R11	R6.2 is covered in proposed TOP-001-2, Requirement R5. R6.3 – moved to proposedTOP-001-2, Requirement R5. R6.4 – moved to proposed TOP-001-2, Requirement R11. TOP-001-2, Purpose: To prevent instability, uncontrolled separation, or ~~cascading outages~~Cascading Outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load.

		TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard TOP-005-2 — Operational Reliability Information		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area. 1.1 - Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data**"** and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.	Approved IRO-010-1a, Requirement R3	Moved to approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Deleted	Confidentiality is not a reliability issue, but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.
R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.		specifications for data.
R4. Each Purchasing-Selling Entity shall provide information, as requested by its Host Balancing Authorities and Transmission Operators, to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted	Deleted as redundant to NAESB standard –All operating data that a Purchasing Selling Entity has, that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-2 – Monitoring System Conditions		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. 1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. 1.2 - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	R1 & R1.1 are replaced by proposed TOP-003-2, Requirement R1. R1.2 – replaced by approved IRO-010-1a, Requirement R3. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator,

Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.		Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3. Approved BAL-005-0.1b. Proposed TOP-001-2, Requirement R10. Approved IRO-008-1, Requirement R2.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and ~~cascading~~ Cascading outages. The act of monitoring is un-measureable. Entities will be in violation of other standards if they don't perform adequate monitoring. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs, and approved IRO-008-1, Requirement R2 for Real-time assessments every 30 minutes for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that

		all ~~facilities~~Facilities and ~~load~~Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the ~~system~~System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and ~~c~~Cascading outages.
R4. Each Transmission Operator~~,~~ and Balancing Authority shall have information, including weather forecasts and past load	Proposed TOP-003-2, Requirements R1 & R2	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority.

patterns, available to predict the system's near-term load pattern.	Approved IRO-010-1a, Requirement R3.	Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and ~~cascading~~ Cascading outages.
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.	Deleted	Deleted as this is covered in the certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs; approved IRO-008-1, Requirement R2 for ~~real~~Real-time assessments every 30 minutes for Reliability Coordinators BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all ~~facilities~~Facilities and ~~load~~Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the ~~system~~System to within limits when an

		IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R7 for Transmission Operator avoiding IROLs. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all ~~facilities~~Facilities and ~~load~~Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.
R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, Requirement R2 for Transmission Operator avoiding underfrequency; approved EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the

		Regulating Reserve. The standard also ensures that all ~~facilities~~Facilities and ~~load~~Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. EOP-003-1, R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic ~~load~~Load shedding for underfrequency or undervoltage conditions. EOP-006-2, R8. The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization.
Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded, and the actions being taken to return the system to within limits.	Proposed TOP-001-2, Requirement R10	Moved to proposed TOP-001-2, Requirement R10. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the ~~system~~System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.
R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	Proposed TOP-001-2, Requirement R11	Moved to proposed TOP-001-2, Requirement R11. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. A Transmission Operator shall take all appropriate actions, up to and including shedding firm load,	Approved EOP-003-1, Requirements R1	Replaced by approved EOP-003-1, Requirements R1. EOP-003-1, R1. After taking all other remedial steps, a

or directing the shedding of firm load, in order to comply with Requirement R2.	and in proposed EOP-003-2, Requirement R1	Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer ~~load~~Load rather than risk an uncontrolled failure of components or ~~cascading~~ Cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	Approved IRO-008-1, Requirement R3	Replaced by approved IRO-008-1, Requirement R3. IRO-008-1, R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.
Standard TOP-008-1 - Response to Transmission Limit Violations		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in New Standard or Comment**
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	Approved EOP-003-1, Requirements R1 and in proposed EOP-003-2, Requirement R1 Proposed TOP-001-2, Requirement R11	Replaced by approved EOP-003-1, Requirements R1 and proposed TOP-001-2, Requirement R11. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer ~~load~~Load, rather than risk an uncontrolled failure of components or ~~cascading outages~~Cascading Outages of the Interconnection. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the	Proposed TOP-001-2, Requirements R7 and R9 Approved IRO-009-1, Requirement R5	First sentence – Replaced by proposed TOP-001-2, Requirements R7 and R9. Second sentence – Replaced by approved IRO-009-1, Requirement R5 for the Reliability Coordinator who is now responsible for such matters. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection

Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.		Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. IRO-009-1, R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	Deleted	Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other ~~Reliability~~ reliability ~~Standards~~ standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	Proposed TOP-003-2, Requirement R1 Proposed TOP-002-3, Requirement R1 Proposed TOP-001-2, Requirement R7 Proposed TOP-001-2, Requirement R11	Data piece is replaced by proposed TOP-003-2, Requirement R1. Analysis tools are covered in the certification process for core capabilities and, therefore, are not needed here. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Replaced by proposed TOP-002-3, Requirement R1 for analysis. Replaced by proposed TOP-001-2, Requirement R7 for real-time analysis required for IROL mitigation.

		Proposed TOP-001-2, Requirement R11 covers mitigation of limit violations. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard PER-001-0 - Operating Personnel Responsibility and Authority		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in New Standard or Comment**
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.	Deleted	In FERC Order 693a, ~~paragraph~~Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of ~~Reliability~~ reliability ~~Standards~~ standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and Balancing Authorities and that makes this requirement superfluous and, thus, it can be deleted. FERC Order 693a, ~~paragraph~~Paragraph 112: In response to Avista, the Commission clarifies that a ~~reliability~~ Reliability ~~coordinator's~~ Coordinator's authority to issue directives arises out of the Commission's approval of ~~Reliability~~ reliability ~~Standards~~ standards that mandate compliance with

		such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to ~~section~~ Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a ~~reliability~~ Reliability ~~coordinator's~~ Coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, ~~we view~~ these are~~as~~ vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
Standard PRC-001-1 – System Protection Coordination		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Proposed Language in New Standard or Comment**
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others: R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.		
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

Standards Announcement

Project 2007-03 Real-Time Transmission Operations

Three Recirculation Ballot Windows Open April 27, 2012 through 8 p.m. Eastern on May 6, 2012

Now Available

The Real-time Operations Standards Drafting Team (RTO SDT) made the following minor revisions to three standards in response to stakeholder comments from the posting that ended on April 20, 2012:

- TOP-001-2 Transmission Operations:
  - Deleted Operations Planning from the Time Horizons for Requirement R1
  - Added clarifying language to the VSLs for Requirements R3, R5, and R6 for consistency with Requirement R8
- TOP-002-3 Operations Planning:
  - Changed from 3 months to 90 calendar days in Data Retention for consistency
- TOP-003-2 Operational Reliability Data:
  - Added analysis functions to Requirement R2, Part 2.1 for consistency with the main requirement

Recirculation ballots of the following standards are **open through 8 p.m. Eastern on Sunday, May 6, 2012:**

- TOP-001-2 Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Clean and redline versions of these standards and the associated single implementation plan and VRFs and VSLs, are posted on the project webpage. Note that TOP-001-2, TOP-002-3, and TOP-003-2 reflect the merging of the following ten standards into three standards, making it impractical to post a "redline" of the three proposed standards that shows the changes to the last balloted versions of these standards. The last approved versions of the standards listed below, as well as a redline showing the proposed modifications to PRC-001-1 have been posted on the project's web page for easy reference.

- PER-001-0.1 Operating Personnel Responsibility and Authority
- PRC-001-2 System Protection Coordination
- TOP-001-1 Reliability Responsibilities and Authorities
- TOP-002-2a Normal Operations Planning
- TOP-003-1 Planned Outage Coordination

- TOP-004-2 Transmission Operations
- TOP-005-2 Operational Reliability Information
- TOP-006-2 Monitoring System Conditions
- TOP-007-0 Reporting SOL and IROL Violations
- TOP-008-1 Response to Transmission Limit Violations

Instructions

In the recirculation ballot, votes are counted by exception. Only members of the ballot pools may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the recirculation ballot. Members of the ballot pools associated with this project may log in and submit their votes for the standards by clicking here.

Next Steps

Voting results will be posted and announced after the ballot windows close. If approved, the standard(s) will be submitted to the Board of Trustees for adoption.

Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate. For more information or assistance, please contact Monica Benson at monica.benson@nerc.net.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Announcement

Project 2007-03 – Real-time Operations

Recirculation Ballot Results

Now Available

Recirculation ballots of three Real-time Operations standards concluded Sunday May 6, 2012:

- TOP-001-2 Transmission Operations
- TOP-002-3 Operations Planning
- TOP-003-2 Operational Reliability Data

Voting statistics for each ballot are listed below, and the Ballots Results page provides a link to the detailed results.

Standard	Quorum	Approval
TOP-001-2 Transmission Operations	Quorum: 79.36%	Approval: 76.84%
TOP-002-3 Operations Planning	Quorum: 79.36%	Approval: 88.11%
TOP-003-2 Operational Reliability Data	Quorum: 79.36%	Approval: 80.79%

Next Steps

TOP-001-2 - Transmission Operations, TOP-002-3 - Operations Planning, and TOP-003-2 - Operational Reliability will be presented to the NERC Board of Trustees for adoption and subsequently filed with regulatory authorities. The VRFs and VSLs for all three standards (unchanged from those included in the versions of the standards posted for recirculation ballot) will be presented to the board for approval.

Background

The Project 2007-03 drafting team has attempted to eliminate redundancy in the Transmission Operations (TOP) family of standards. As part of this process, the drafting team has made an effort to reorganize the standards and requirements in a more logical manner. The team has also made revisions to address outstanding Order 693 directives.

Additional information is available on the project page.

Standards Development Process

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For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2007-03 Recirculation Ballot TOP-001-2
Ballot Period:	4/27/2012 - 5/6/2012
Ballot Type:	Initial
Total # Votes:	296
Total Ballot Pool:	373
Quorum:	**79.36 % The Quorum has been reached**
Weighted Segment Vote:	76.84 %
Ballot Results:	**The Standard has Passed.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	103	1	53	0.757	17	0.243	5	28
2 - Segment 2.	11	0.9	8	0.8	1	0.1	0	2
3 - Segment 3.	82	1	51	0.797	13	0.203	4	14
4 - Segment 4.	27	1	16	0.762	5	0.238	1	5
5 - Segment 5.	82	1	45	0.776	13	0.224	8	16
6 - Segment 6.	47	1	27	0.794	7	0.206	3	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.6	4	0.4	2	0.2	0	2
9 - Segment 9.	4	0.3	1	0.1	2	0.2	1	0
10 - Segment 10.	9	0.6	5	0.5	1	0.1	3	0
Totals	**373**	**7.4**	**210**	**5.686**	**61**	**1.714**	**25**	**77**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt		
1	Muscatine Power & Water	Tim Reed		
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F Afranji	Affirmative	

1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Negative	View
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Affirmative	View
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon		
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Affirmative	View
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	View
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	View
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Negative	View
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	View
3	Seattle City Light	Dana Wheelock	Affirmative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	View

4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Negative	
5	AES Corporation	Leo Bernier	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	View
5	Consumers Energy	James B Lewis	Negative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Affirmative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	View
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox		
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	MidAmerican Energy Co.	Dennis Kimm		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Affirmative	

6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		Merle Ashton		
8		James A Maenner		
8	INTELLIBIND	Kevin Conway	Negative	View
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Negative	View
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Negative	View
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Negative	View
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Abstain	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Ballot Results	
Ballot Name:	Project 2007-03 Recirculation Ballot TOP-002-3 April 2012
Ballot Period:	4/27/2012 - 5/6/2012
Ballot Type:	Initial
Total # Votes:	296
Total Ballot Pool:	373
Quorum:	**79.36 % The Quorum has been reached**
Weighted Segment Vote:	88.11 %
Ballot Results:	**The Standard has Passed.**

Summary of Ballot Results

			Affirmative		Negative		Abstain	
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	# Votes	No Vote
1 - Segment 1.	103	1	59	0.843	11	0.157	5	28
2 - Segment 2.	11	0.9	9	0.9	0	0	0	2
3 - Segment 3.	82	1	56	0.903	6	0.097	6	14
4 - Segment 4.	27	1	16	0.8	4	0.2	2	5
5 - Segment 5.	82	1	46	0.821	10	0.179	10	16
6 - Segment 6.	47	1	29	0.853	5	0.147	3	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	4	0.4	1	0.1	1	2
9 - Segment 9.	4	0.3	3	0.3	0	0	1	0
10 - Segment 10.	9	0.7	7	0.7	0	0	2	0
Totals	**373**	**7.4**	**229**	**6.52**	**37**	**0.88**	**30**	**77**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	View
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt		
1	Muscatine Power & Water	Tim Reed		
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Brenda Pulis	Negative	View
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F Afranji	Affirmative	

1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	View
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	View
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon		
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Affirmative	View
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Abstain	
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Affirmative	View
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	View
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	View
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	

4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Abstain	
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	View
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	View
5	Consumers Energy	James B Lewis	Negative	
5	Cowlitz County PUD	Bob Essex	Abstain	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Affirmative	

5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	View
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	View
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Affirmative	
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6	Omaha Public Power District	David Ried	Affirmative	

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6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		James A Maenner		
8		Merle Ashton		
8	INTELLIBIND	Kevin Conway	Negative	View
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Stacy Dochoda	Affirmative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Ballot Results	
Ballot Name:	Projectd 2007-03 Recirculation TOP-003-2 April 2012
Ballot Period:	4/27/2012 - 5/6/2012
Ballot Type:	Initial
Total # Votes:	296
Total Ballot Pool:	373
Quorum:	**79.36 % The Quorum has been reached**
Weighted Segment Vote:	80.79 %
Ballot Results:	**The Standard has Passed.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No Vote
			# Votes	Fraction	# Votes	Fraction	# Votes	
1 - Segment 1.	103	1	56	0.8	14	0.2	5	28
2 - Segment 2.	11	0.9	9	0.9	0	0	0	2
3 - Segment 3.	82	1	56	0.862	9	0.138	3	14
4 - Segment 4.	27	1	15	0.682	7	0.318	0	5
5 - Segment 5.	82	1	43	0.741	15	0.259	8	16
6 - Segment 6.	47	1	27	0.794	7	0.206	3	10
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	8	0.5	4	0.4	1	0.1	1	2
9 - Segment 9.	4	0.3	3	0.3	0	0	1	0
10 - Segment 10.	9	0.7	5	0.5	2	0.2	2	0
Totals	**373**	**7.4**	**218**	**5.979**	**55**	**1.421**	**23**	**77**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Abstain	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Negative	View
1	CenterPoint Energy Houston Electric	Dale Bodden		
1	Central Maine Power Company	Kevin L Howes		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	View
1	City of Vero Beach	Randall McCamish		
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Abstain	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	View
1	Dairyland Power Coop.	Robert W. Roddy	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	View
1	East Kentucky Power Coop.	George S. Carruba	Negative	View
1	Empire District Electric Co.	Ralph F Meyer	Affirmative	
1	Entergy Services, Inc.	Edward J Davis	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Gainesville Regional Utilities	Luther E. Fair		
1	Georgia Transmission Corporation	Harold Taylor	Affirmative	
1	Grand River Dam Authority	James M Stafford	Abstain	
1	Great River Energy	Gordon Pietsch	Affirmative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stanley T Rzad		
1	Lake Worth Utilities	Walt J Gill		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Lone Star Transmission, LLC	Julius Horvath		
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	Ly M Le		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	View
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	
1	Minnkota Power Coop. Inc.	Richard Burt		
1	Muscatine Power & Water	Tim Reed		
1	National Grid	Saurabh Saksena		
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	New York State Electric & Gas Corp.	Raymond P Kinney		
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Negative	
1	Omaha Public Power District	Doug Peterchuck	Negative	View
1	Oncor Electric Delivery	Brenda Pulis	Affirmative	
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Colt Norrish		
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F Afranji	Affirmative	

1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Chelan County	Chad Bowman		
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Raj Rana	Rajendrasinh D Rana		
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.		
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Rich Salgo	Negative	
1	South Texas Electric Cooperative	Richard McLeon		
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James Jones	Affirmative	View
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	View
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Charles B Manning	Affirmative	View
2	Independent Electricity System Operator	Kim Warren		
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox		
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	View
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Affirmative	
3	City of Garland	Ronnie C Hoeinghaus	Negative	View
3	City of Green Cove Springs	Gregg R Griffin		
3	City of Redding	Bill Hughes	Affirmative	
3	City Water, Light & Power of Springfield	Roger Powers		
3	Clatskanie People's Utility District	Brian Fawcett		
3	Cleco Corporation	Michelle A Corley	Affirmative	
3	Colorado Springs Utilities	Lisa Cleary		
3	ComEd	Bruce Krawczyk	Affirmative	View
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	View
3	Constellation Energy	CJ Ingersoll	Abstain	
3	Consumers Energy	David A. Lapinski	Negative	
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	CPS Energy	Jose Escamilla	Affirmative	

3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F. Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt		
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power and Light / NextEra Energy	Chantel Haswell		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Abstain	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia Systems Operations Corporation	William N. Phinney	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Sam Kokkinen	Affirmative	View
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	View
3	Manitoba Hydro	Greg C. Parent	Affirmative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	View
3	Municipal Electric Authority of Georgia	Steven M. Jackson	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	View
3	Nebraska Public Power District	Tony Eddleman	Affirmative	View
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Omaha Public Power District	Blaine R. Dinwiddie		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	John Apperson		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson		
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Rutherford EMC	Thomas M Haire	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Abstain	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	View

4	Consumers Energy	David Frank Ronk	Negative	
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Imperial Irrigation District	Diana U Torres	Affirmative	
4	LaGen	Richard Comeaux	Negative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Oklahoma Municipal Power Authority	Terri Pyle		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	AES Corporation	Leo Bernier	Abstain	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	View
5	BrightSource Energy, Inc.	Chifong Thomas		
5	Chelan County Public Utility District #1	John Yale	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Grand Island	Jeff Mead	Abstain	
5	City of Redding	Paul Cummings	Affirmative	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick		
5	City of Tallahassee	Brian Horton	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Abstain	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	View
5	Consumers Energy	James B Lewis	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	View
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	East Kentucky Power Coop.	Stephen Ricker	Negative	View
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	ExxonMobil Research and Engineering	Martin Kaufman	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	View
5	Florida Municipal Power Agency	David Schumann	Negative	View
5	Great River Energy	Preston L Walsh	Affirmative	View
5	Green Country Energy	Greg Froehling		
5	I do not represent an Entity	Bruce Paggeot		
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Negative	
5	Lakeland Electric	James M Howard	Negative	View
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom		
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Tom Foreman	Affirmative	
5	Luminant Generation Company LLC	Mike Laney	Negative	View

5	Manitoba Hydro	S N Fernando	Affirmative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Affirmative	View
5	New Harquahala Generating Co. LLC	Nathaniel Larson		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	View
5	Omaha Public Power District	Mahmood Z. Safi	Negative	View
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Pete Ungerman		
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Fossil LLC	Mikhail Falkovich	Affirmative	
5	Puget Sound Energy, Inc.	Tom Flynn	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	View
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	Southern California Edison Co.	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	View
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Barry Ingold		
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Arizona Public Service Co.	Justin Thompson		
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	View
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski		
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	View
6	Constellation Energy Commodities Group	Brenda L Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager		
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	View
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Negative	View
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brad Jones	Negative	View
6	Manitoba Hydro	Daniel Prowse	Affirmative	View
6	MidAmerican Energy Co.	Dennis Kimm		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	NRG Energy, Inc.	Alan Johnson	Abstain	
6	Omaha Public Power District	David Ried	Negative	View

6	Orlando Utilities Commission	Claston Augustus Sunanon		
6	PacifiCorp	Scott L Smith	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Abstain	
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Suzanne Ritter		
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Shell Energy North America (US), L.P.	Paul Kerr	Affirmative	
6	South California Edison Company	Lujuanna Medina		
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8		Merle Ashton		
8		James A Maenner		
8	INTELLIBIND	Kevin Conway	Negative	View
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William M Chamberlain	Abstain	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	National Association of Regulatory Utility Commissioners	Diane J Barney	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Abstain	
10	Midwest Reliability Organization	James D Burley	Affirmative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Abstain	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool RE	Stacy Dochoda	Negative	
10	Texas Reliability Entity, Inc.	Larry D. Grimm	Negative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Exhibit G

Standard Drafting Team Roster for NERC Standards Development Project 2007-03

Project 2007-03 Real-time Transmission Operations
Drafting Team Roster

Name and Title	Company and Address	Contact Info	Bio
James Case, P.E. Director, Weekly Operations & SDT Chair	Entergy Services 6540 Watkins Drive Jackson, MS 39213	1.601.985.2345 jcase@entergy.com	Jim Case was named director of weekly operations in June. 2008. Immediately prior to being named to this position, Mr. Case served in transmission operations as manager of transmission system security. As director of weekly operations, Mr. Case is responsible for the design, implementation and maintenance of procedures and processes necessary to ensure compliance with Entergy's transmission tariff on file with the Federal Energy Regulatory Commission that governs Entergy's weekly procurement process. Mr. Case also leads the implementation of integration into the MISO RTO for Entergy's transmission function. Mr. Case has over thirty-eight years of electric utility experience, most recently in transmission operations. He has experience in all phases of transmission and distribution, including field engineering, construction management, distribution standards, and bulk power operations. Mr. Case currently directs a group that performs security-constrained unit commitment including independent offers on a week-ahead basis for Entergy. In addition to his previous assignment in transmission operations, he has served as manager of transmission security coordination, staff engineer in distribution standards, and district engineer in the south-central district of Entergy Mississippi. Before joining Entergy, Mr. Case worked for the Union Carbide Nuclear Division and Gulf Power Company. Mr. Case is active nationally in NERC. He is a member of the NERC Operating Committee, Chair of the SERC Operating Committee, Chair of the NERC Real-time Operations Standards Drafting Team, member of the Reliability Coordination Standards Drafting Team, member of the

			Interconnected Reliable Operations Standards Drafting Team, past member of the Version 0 Standards Drafting Team, the Reliability Coordination Working Group, the Congestion Management Working Group, and the ANSI C62 working group concerned with surge arrester standards. Mr. Case has a bachelor's degree in electrical engineering from Mississippi State University and a master's degree in business administration from the University of Arkansas at Little Rock. Mr. Case is a senior member of the Institute of Electrical and Electronics Engineers, Inc., a member of the Power Engineering Society, and is a registered professional engineer in Mississippi. Mr. Case is a member of Eta Kappa Nu, Tau Beta Pi, Beta Gamma Sigma and Alpha Epsilon Lambda.
Karl Tammar Transmission Operations Manager & SDT Vice Chair	Sharyland Utilities 6900 Interstate 40 West, Suite 100 Amarillo, TX 79119	1.806.358.9070 ktammar@sharyland.com	Karl Tammar is the Manager of Transmission Operations for Sharyland Utilities, LLP. Mr. Tammar joined Sharyland Utilities in October 2010. He is responsible for developing and leading the transmission operations organization for Sharyland Utilities, including building a new transmission operations center to control and operate Sharyland's transmission assets. Mr. Tammar has over 30 years of experience in the electric utility industry that includes management and engineering positions with electric utility companies including Northeast Utilities, Montana-Dakota Utilities, and the New York Independent System Operator. He has served on numerous NERC and regional reliability committees, task forces, and working groups; most recently as the Vice Chair of the NERC Real-time Operations Standards Drafting Team. Mr. Tammar has an MBA in Accounting from Union College and a Master's in Electric Power Engineering from Rensselaer Polytechnic Institute. He is a member of the Institute of Electrical and Electronics Engineers (IEEE), and a member of the IEEE's Power and Energy Society and Technology

			Management Council.
Albert DiCaprio Strategist	PJM 955 Jefferson Ave. Valley Forge Corporate Center Norristown, PA 19403	1.610.666.8854 dicapram@pjm.com	Mr. DiCaprio has been employed by PJM since 1970. His experience at PJM includes the System Operations Department in which he helped develop PJM's generation control program, PJM's Accounting for regulation program, and PJM's Fuel Supply Emergency procedures; in the System Performance Department he initiated performance monitoring and benchmarking programs and PJM's Energy by Fuel type tracking system; and he helped launch PJM's first retail customer support program. As Senior Strategist, Mr. DiCaprio provides analysis and support for PJM positions on NERC standards and FERC initiatives. Mr. DiCaprio has served on various NERC committees most notably as Chairman of the Performance Subcommittee when the first Control Performance Standard was approved and on the Task Force whose efforts led to the development of the NERC Functional Model. Mr. DiCaprio serves as the chairman of the ISO/RTO's Standards Review Committee who review and comment on NERC Reliability Standards, NAESB Business Practices, and FERC initiatives related to reliability standards. Active in the IEEE, Mr. DiCaprio is a senior member and has published various papers and has served on Technical Activities committees for two Joint IEEE-CIGRE conferences. Internationally, Mr. DiCaprio serves as the chairman of the International Group on Comparison of Transmission Operation Practices. Mr. DiCaprio has been part of CIGRE's initiative into Energy Markets and has been active with Study Committee C5 (Markets and Regulation) since its beginning in 2000 and received the CIGRE 2009 Technical Committee Award for his contributions to the Study Committee. Mr. DiCaprio is also active in a Joint Working Group with Markets and Operations, and Working Groups on System Design (WG C5-7) and on Integration of Renewable

			resources and Demand-side Management (WG C5-11). Mr. DiCaprio has a Bachelor's Degree in Electrical Engineering from Drexel University and a Master's Degree in System Operations from the University of PA.
Jason Marshall Director, Reliability Compliance	ACES Power marketing 4140 West 99th Street Carmel, IN 46032	1.317.344.7204 jmarshall@acespower.com	Jason Marshall is currently Director of Reliability Compliance for ACES Power Marketing (APM) in Carmel, IN. Mr. Marshall joined APM in April 2011 in this role. Mr. Marshall is currently responsible for leading APM's reliability compliance support service which provides advice, guidance, and processes to share resources and reliability compliance intelligence among APM's members and the National Rural Electric Cooperative Association (NRECA). Mr. Marshall has 15 years of experience in the energy industry including extensive experience in bulk power operations and ERO compliance. Mr. Marshall began his career in 1996 with Duke Energy as an Associate Engineer supporting their transmission tariff and bulk power operations. Immediately prior to joining APM, Mr. Marshall held positions of progressively increasing responsibility in operations engineering and ERO standards development and compliance at Midwest ISO in Carmel, IN. Mr. Marshall also has worked as a reliability coordinator for the MAIN Coordination Center in Lombard, IL. Mr. Marshall's industry experience includes reliability coordination, transmission operations, balancing authority operations, operations planning, EMS support, transmission tariff administration, reliability policy analysis, and new business start up. He has served on numerous NERC committees, drafting teams, and task forces. Mr. Marshall also has served as chairman of several RFC standards drafting teams and vice-chairman of the ISO/RTO Council's Standards Review Committee. Mr. Marshall graduated with a Bachelor of Science degree in electrical engineering from Rose-Hulman Institute of Technology. He also received a Master of Science in Electrical Engineering (with a power systems

			emphasis) from Clemson University and a Master of Business Administration from the University of Indianapolis. Mr. Marshall is a NERC-certified Reliability Operator and a Registered Professional Engineer in the states of North Carolina and Indiana.
H. Steven Myers Principal, Operatoing & Planning Standards	ERCOT 2705 West Lake Drive Taylor, TX 76574	1.512.248.3077 smyers@ercot.com	Steve Myers, Principal, Operating & Planning Standards at the Electric Reliability Council of Texas (ERCOT), has over forty-two years of electric system operations experience. Mr. Myers first joined ERCOT in 1996 as the Security Center Manager at the inception of the ERCOT Independent System Operator (ISO). During his time at ERCOT, he has served as Security Center Manager, Manager of System Operations, Manager of Operations Support, Manager of Operating Standards, and now as Principal, Operating & Planning Standards. Mr. Myers has served in various positions related to NERC activities, standards development, and reliability standards compliance. He has been a member of the NERC RCWG, NERC ORS, the original RRSWG, the Version 0 Operating Standards SDT, numerous Reliability Standards SDTs, the NERC FMWG, and is presently an ISO/RTO Segment representative to the NERC Standards Committee. Mr. Myers is also a member of the ISO/RTO Council Standards Review Committee (SRC). Prior to joining ERCOT, Mr. Myers served as Manager of the North Texas Security Center. He also served as Operations Supervisor and as Supervisor of Operations Engineering for an investor-owned electric utility; including generation and transmission operations. As a more junior engineer, he served as an engineer in electrical distribution, with responsibilities including supervision of a transformer repair shop, supervision of an underground network group, and as an operations engineer at the system control center.

			Mr. Myers is a graduate of New Mexico State University, with a Bachelor of Science in Electrical Engineering (BSEE). He has a Master of Business Administration (MBA) degree in Management from the University of Texas at Arlington, and is a Registered Professional Engineer in the State of Texas. Mr. Myers served as an officer in the U. S. Naval Reserve as an Assistant Resident Officer in Charge of Construction in San Diego, California. His electrical engineering training enabled his oversight of all contracts for electrical systems on all bases in the San Diego area. Mr. Myers also gained experience with oversight of contracts of every nature on three assigned Navy bases in the area.
Gregory Van Pelt	CAISO 250 Outcropping Way Folsom, CA 95630	1.916.351.2190 gvanpelt@caiso.com	Gregory Van Pelt is currently an External Affairs Manager for the California Independent System Operator (ISO). Mr. Van Pelt has been involved in power system operations for nearly 40 years and was part of the original start-up staff at the ISO. Prior to his current assignment, his responsibilities included real-time operations, operations training, outage management, regional coordination and compliance, as well as developing and coordinating emergency response actions. Before coming to the ISO, Mr. Van Pelt spent 25 years with the Southern California Edison Company where his responsibilities were primarily in Electric System Operations and Emergency Management.

Exhibit H

Southwest Blackout Event Analysis

Analysis of PSW Report Recommendations Addressed by Currently Enforceable and Revised Board-Approved TOP Standards[1]

Current Standards	Future Standards
Report Recommendation 2: *TOPs and BAs should ensure that their next-day studies are updated to reflect next-day operating conditions external to their systems, such as generation and transmission outages and scheduled interchanges, which can significantly impact the operation of their systems. TOPs and BAs should take the necessary steps, such as executing nondisclosure agreements, to allow the free exchange of next-day operations data between operating entities. Also, RCs should review the procedures in the region for coordinating next-day studies, ensure adequate data exchange among BAs and TOPs, and facilitate the next-day studies of BAs and TOPs.*	
TOP-002-2a, Requirement R19: R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations. **IRO-008-1, Requirements R1 and R3:** R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share	**Proposed TOP-002-3, Requirement R1:** R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions **that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions**. (Emphasis added - Note that the nqualifier "accurate" was removed as ambiguous; the concept of accuracy is captured in the bolded phrase. Without a reasonable degree of accuracy in its Operational Planning Analysis, a TOP cannot meet this Requirement.) **The following Requirements from currently enforceable Reliability Standards will remain in effect and contribute to meeting Report Recommendation 2:**

[1] This analysis was prepared at the request of the NERC Board of Trustees, for the purpose of determining whether the TOP standards as revised under Project 2007-03 Real-time Operations were consistent with the recommendations in the 2011 Southwest Blackout Event. *Arizona-Southern California Outages on September 8, 2011, Causes and Recommendations*, prepared by the Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, April 2012. This report is available at: http://www.nerc.com/files/AZOutage_Report_01MAY12.pdf. While that report contained a number of recommendations that were not specific to real-time operations, those were not included in this analysis because they were not pertinent to the standards in question (i.e., the Board-approved TOP-001-2, TOP-002-3, and TOP-003-2).

Analysis of PSW Report Recommendations Addressed by Currently Enforceable and Revised Board-Approved TOP Standards[1]

Current Standards	Future Standards
its results with those entities that are expected to take those actions. **IRO 010-1a, Requirements R1 and R3:** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: s R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. R1.2. Mutually agreeable format. R1.3. Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses). R1.4. Process for data provision when automated Real-Time system operating data is unavailable. R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship. **IRO 004-2, Requirement R1:** R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its	**IRO-008-1, Requirements R1 and R3:** R1. Each Reliability Coordinator shall perform an Operational Planning Analysis to assess whether the planned operations for the next day within its Wide Area, will exceed any of its Interconnection Reliability Operating Limits (IROLs) during anticipated normal and Contingency event conditions R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions. **IRO 010-1a, Requirements R1 and R3:** R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and cascading outages. The specification shall include the following: s R1.1. List of required data and information needed by the Reliability Coordinator to support Real-Time Monitoring, Operational Planning Analyses, and Real-Time Assessments. R1.2. Mutually agreeable format. R1.3. Timeframe and periodicity for providing data and information (based on its hardware and software requirements, and the time needed to do its Operational Planning Analyses). R1.4. Process for data provision when automated Real-Time

<table>
<tr><th colspan="2">Analysis of PSW Report Recommendations Addressed by
Currently Enforceable and Revised Board-Approved TOP Standards[1]</th></tr>
<tr><th>Current Standards</th><th>Future Standards</th></tr>
<tr><td>Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.</td><td>system operating data is unavailable.

R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.

IRO 004-2, Requirement R1:
R1. Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.</td></tr>
<tr><td colspan="2">Report Recommendation 11: TOPs should engage in more real-time data sharing to increase their visibility and situational awareness of external contingencies that could impact the reliability of their systems. They should obtain sufficient data to monitor significant external facilities in real time, especially those that are known to have a direct bearing on the reliability of their system, and properly assess the impact of internal contingencies on the SOLs of other TOPs. In addition, TOPs should review their real-time monitoring tools, such as State Estimator and RTCA, to ensure that such tools represent critical facilities needed for the reliable operation of the BPS. TOPs should take measures to ensure that their real-time tools are adequate, operational, and run frequently enough to provide their operators the situational awareness necessary to identify and plan for contingencies and reliably operate their systems.</td></tr>
<tr><td>TOP-006-1, Requirement R2, R5, and R6:
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.

R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.</td><td>Proposed TOP-003-2 Requirements R1 (Transmission Operator) and R2 (Balancing Authority) cover the development of a data specification that specifically covers the respective entities' analysis data needs.

R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its Operational Planning Analyses and Real-time monitoring. The specification shall include:

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses and Real-</td></tr>
</table>

Analysis of PSW Report Recommendations Addressed by Currently Enforceable and Revised Board-Approved TOP Standards[1]

Current Standards	Future Standards
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations. **TOP-008-1, Requirement R4:** R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	time monitoring. R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring. The specification shall include: 2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring. **Proposed TOP-003-2 Requirements R3 (Transmission Operator) and R4 (Balancing Authority)** address the distribution of the data specifications to applicable entities. Requirement R5 then mandates that the requested applicable entities must supply the data. R3. Each Transmission Operator shall distribute its data specification, as developed in Requirement R1, to entities that have data required by the Transmission Operator's Operational Planning Analysis and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. R4. Each Balancing Authority shall distribute its data specification, as developed in Requirement R2, to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring process used in meeting its NERC-mandated reliability requirements. R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.

Analysis of PSW Report Recommendations Addressed by Currently Enforceable and Revised Board-Approved TOP Standards[1]	
Current Standards	**Future Standards**
	Additionally, the scope of Project 2009-02 Real-time Monitoring and Analysis Capabilities, currently in development, includes establishment of requirements for monitoring and analysis capabilities provided to System Operators to support Real-time System Operations.
TOP-004-2, Requirement R4 R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	Proposed TOP standards (TOP-001-2, TOP-002-3, and TOP-003-2) do not include an explicit reference to **'unknown state'** since system limits can and should be determined and conditions can be monitored to know when they have been exceeded. The proposed TOP standards prohibit operation outside of IROLs, or SOLs identified in TOP 001-2 R8, which supports continuous reliability and accountability. **Proposed TOP-001-2, Requirements R7, R8, and R9.** R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. Finally, approved EOP-006-2, which becomes enforceable on 7/1/2013

Analysis of PSW Report Recommendations Addressed by Currently Enforceable and Revised Board-Approved TOP Standards[1]

<table>
<tr><th>Current Standards</th><th>Future Standards</th></tr>
<tr><td></td><td>supports these Requirements to ensure recovery. EOP-006-2 has the following purpose: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.</td></tr>
<tr><td colspan="2">Report Recommendation 12: TOPs should review existing operating processes and procedures to ensure that post-contingency mitigation plans reflect the time necessary to take mitigating actions, including control actions, to return the system to a secure N-1 state as soon as possible but no longer than 30 minutes following a single contingency. As part of this review, TOPs should consider the effect of relays that automatically isolate facilities without providing operators sufficient time to take mitigating measures.</td></tr>
<tr><td>TOP-004-2, Requirement R2:
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

TOP-002-2a, Requirement R10:
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).

TOP-008-1, Requirements R1 and R2:
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.

R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System</td><td>The Proposed TOP standards prohibit operation outside of IROLs, or SOLs identified in TOP 001-2 R8. The proposed standards reflect the responsibilities contained in the Functional Model. The TOP is accountable to remain within IROLs and SOLs provided by the RC, and any SOLs that the TOP establishes using the RCs methodology. TOP-001-2, Requirement R7 requires that a Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v which is a more limiting circumstance than the current standards, since T_v is less than 30 minutes. Requirement R8 then continues to raise the bar by including selected SOLs that should receive the same basic treatment as IROLs while limiting operations in Requirement R9 to durations that can't exceed the applicable ratings. Finally, Requirement R11 states that the Transmission Operator must act, or direct others to act, to mitigate any such situations.

TOP-001-2, Requirements R7, R8, R9, and R11:
R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.</td></tr>
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Analysis of PSW Report Recommendations Addressed by Currently Enforceable and Revised Board-Approved TOP Standards[1]	
Current Standards	**Future Standards**
to the most limiting parameter.	R8. Each Transmission Operator shall inform its Reliability Coordinator of each SOL which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area based on its assessment of its Operational Planning Analysis. R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. Finally, this recommendation and the above Requirements are supported by the currently enforceable **EOP-003-1, Requirement R1**. R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load, rather than risk an uncontrolled failure of components or Cascading Outages of the Interconnection. Proposed standards do not use the word 'immediate' because it is not measurable. The concept of 'immediate' action has been systematically replaced within NERC standards as they are revised to improve accountability. For example, revised EOP standards require action in time to avoid cascading; the proposed TOP standards require action within a determined time limit (T_v) based on system models.

Current Standards	Future Standards
TOP-002-2a, Requirement R6: R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	This Requirement is replaced by proposed TOP-002-3, Requirement R1 and R2. The N-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning. The proposed standard is an improvement over the current standard because it requires responsible entities to establish limits according to their functional model area of responsibility and prescribes the required actions for operation of the BES in a manner that supports continuous reliability and accountability. **Proposed TOP-002-3, Requirements R1 and R2:** R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability in its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.

Analysis of PSW Report Recommendations Addressed by Currently Enforceable and Revised Board-Approved TOP Standards[1]	
Current Standards	**Future Standards**
Report Recommendation 27: *TOPs should have: (1) the tools necessary to determine phase angle differences following the loss of lines; and (2) mitigation and operating plans for reclosing lines with large phase angle differences. TOPs should also train operators to effectively respond to phase angle differences. These plans should be developed based on the seasonal and next-day contingency analyses that address the angular differences across opened system elements.*	
TOP-004-2, Requirement R6, subrequirement R6.2: R6: Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: R6.2. Switching transmission elements.	Proposed TOP-002-3, Requirement R2 covers the creation of a plan to mitigate situations shown in the Operating Planning Analysis required in TOP-002-3, Requirement R1. SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes consideration of equipment limitations. The proposed standard is an improvement over the current standard because it links to specific limits rather than the ambiguous concept of 'transmission reliability', which is only measurable by its absence. **Proposed TOP-002-3, Requirements R2 and R3:** R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability in its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).

Analysis of PSW Report Recommendations Addressed by Currently Enforceable and Revised Board-Approved TOP Standards[1]	
Current Standards	**Future Standards**
	Further, Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities is underway and will establish requirements for the functionality, performance, and change management capabilities for RC, TOP, GOP, and BA for use by System Operators in support of reliable System operations.

Exhibit I

Resolution of Order No. 693 Directives Assigned to Project 2007-03

Resolution of Issues Assigned to Project 2007-03 Real-time Operations Standard Drafting Team

Standard	Source	Language	Resolution
TOP-001			
TOP-001-1	FERC Order 693	1580 - Consider adding other measures and levels of non-compliance.	Measures and VSLs have been assigned to all requirements.
TOP-001-1	FERC Order 693	1585 - Clarify the definition of "emergency" and define the criteria for entering into the various states. Also define the authority for declaring these states.	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	FERC Order 693	1588 - Consider Santa Clara's comments to provide that the transmission operator may notify the reliability coordinator or the balancing authority that it is removing facilities from service as part of the standards development process.	This is covered in proposed TOP-001-2, Requirement R5.
TOP-001-1	Version 0 Team	What is 'clear decision making authority'?	Requirement using this term was deleted as not needed in a reliability standard. The standards already require the necessary actions.

Standard	Source	Language	Resolution
TOP-001-1	Version 0 Team	Need to define single, central communications point during emergencies	This is an issue for COM standards.
TOP-001-1	Version 0 Team	Some emergencies will require follow up notification as opposed to immediate	Requirements have been re-written to eliminate confusion.
TOP-001-1	Version 0 Team	Define emergency	The RTOSDT feels that the TOP-001 standard should be restricted to Transmission System operations and that definition of operating states more correctly belong in EOP-001 as pointed out in Order 693, paragraph 560. To make certain that the issue is handled there; the RTOSDT has entered an official item in the NERC database of project issues in this regard. This will require the SDT working on revisions to EOP-001 to formally address this concern. EOP-001 is listed in the Reliability Standards Development Plan under Project 2009-03.
TOP-001-1	Version 0 Team	Need to expand included entities	Applicability has been reviewed by the SDT and changed as required.

TOP-003			
TOP-003-0	FERC Order 693	1621 - Incorporate an appropriate lead time for planned outages using suggestions from the various commenters. We direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	The SDT posed a question on this issue as a fact finding exercise in the second posting of this project in order to assist them in making a decision on how to respond to the FERC directive as requested in Order 693 – "The ERO should utilize the information filed by commenters in the Reliability Standards development process." The majority of respondents indicated that they do not feel that there is a reliability based need for such a North American requirement. Several respondents pointed out that such a requirement (if needed at all for reliability) would be better suited to a regional standard and several others stated that such requirements already exist in their particular regions. There are several regions that have existing rules for lead times but they are all different and are based on the requirements of their regional markets. Any attempt to impose a North American standard runs the risk of interfering with those FERC approved markets. While NERC Reliability Standards are intended to promote reliability, they must at the same time accommodate competitive electricity markets. After reviewing the industry comments, the SDT concluded that proposed TOP-003-2 dealing with data specifications adequately cover this issue. The data specification must include any and all data required by the Transmission Operator and Balancing Authority. The SDT intends that planned outage data and timings would be included in such a data specification. Therefore, the SDT has not included a standard lead time in the

			revised requirements.
TOP-004			
TOP-004-1	FERC Order 693	1630 - Modify requirement R4 to state that the system should be restored to respect proven limits as soon as possible taking no more than 30 minutes.	Replaced by proposed TOP-001-2, R7 through R11. T_v is more stringent than the existing 30 minute requirement for IROLs and the selected SOLs are now tied to the specific ratings from which the SOLs were derived. Unknown states, in this context, cannot exist because valid operating limits have been determined for all Facilities in a TOP's footprint. The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to Emergencies.
TOP-004-1	FERC Order 693	1638 - Defines high risk conditions under which the system must be operated to respect multiple outages in requirement R3. We direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process (. . .the Commission proposed to interpret "multiple outages" in the context of Requirement R3 to include multiple element outages resulting from high risk conditions such as hurricanes, wild fires, ice storms or periods of high solar magnetic disturbances during which the probability of multiple outages approaches that of a single element	The SDT feels that proposed EOP-001-2 dealing with emergency operations planning covers the general intent of being prepared to react to the cited situations. The method chosen to respond to a given catastrophic challenge to a localized portion of the bulk power system cannot be predetermined by science; rather, it is an art. Reliability entities develop their response mechanisms based on experience in their local areas to achieve the maximum societal benefit during these periods. In addition, FAC-011-2 and FAC-014-2 deal with specific requirements for dealing with multiple contingencies.

		outage. This is not an exhaustive list but is meant to contain illustrative examples, and the Reliability Standards development process should develop a procedure to identify applicable high risk conditions. Under . . . high-risk conditions, the Commission understands that systems are normally operated in a more secure manner so that the Bulk-Power System can withstand multiple outages. These multiple outages exceed the normal N-1 criterion because the probability of multiple outages during high risk conditions approaches that of a single outage during normal conditions.)	
TOP-004-1	Version 0 Team	Vagueness in application of IROL limits	Requirement moved to proposed TOP-001-2, Requirement R5 and clarified.
Transferred from Project 2007-06			
PRC-001	Project 2007-06	1441- S- Ref 10339 - Clarify the term corrective action. 1440. We believe that [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations.

		System. 1441. We direct the ERO to clarify the term corrective action consistent with this discussion when it modifies PRC-001-1 in the Reliability Standards development process.	
PRC-001	Project 2007-06	1444 - S- Ref 10340 - Consider First Energy and the California PUCs comments about the maximum time for corrective actions in the standards development process. 1428. California PUC contends that imposing a time restriction for returning a system to a stable state may cause more harm than good since additional information and options may be available as time elapses. It repeats its suggestion from its earlier comments on the Staff Preliminary Assessment and proposes the following alternative language: Transmission or generation operators shall carry out corrective control actions, i.e., returning the system to a stable state that respects system requirements as soon as possible, and no longer than 30 minutes, except where a longer response time is feasible, or where a longer response is demonstrated to produce a better ultimate solution without unacceptable interim risk. 1431. FirstEnergy contends that	Addressed in Requirement R5 in proposed TOP-001-2 where the Transmission Operator coordinates its operations. The Transmission Operator is the true functional entity responsible here. Covered as part of the new data specification requirements in proposed TOP-003-2.

		Requirement R2.1 essentially requires generator operators to report all protective relay or equipment failures, since generator operators may not be able to tell which failures will reduce system reliability. FirstEnergy suggests that R2.1 should be revised to require generator operators to report all equipment failures or outages. FirstEnergy further suggests that PRC-001-1 be revised to provide that if a company performs reasonable testing procedures, undiscoverable equipment failures will not be violations of R2.1	
PRC-001	Project 2007-06	1449 - S- Ref 10343 - Para 1420. Once informed, transmission operators must carry out corrective control actions that return the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes. 1440. [t]he transmission operator shall take corrective action as soon as possible refers to transmission operators taking operator control actions. It does not refer to troubleshooting, repairing or replacing failed relays or equipment, etc., since these time-consuming corrective actions would prolong the risk of cascading failures to the Bulk-Power System.	Covered in TOP-001-2, Requirement R11.

Exhibit J

Mapping Document

Mapping Document

Project 2007-03 Real-time Operations

Mapping document showing the translation of TOP-001-1 — Reliability Responsibilities and Authorities; TOP-002-2a — Normal Operations Planning; TOP-003-1 — Planned Outage Coordination; TOP-004-2 — Transmission Operations; TOP-005-2 — Operational Reliability Information; TOP-006-2 – Monitoring System Conditions; TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations; TOP-008-1 - Response to Transmission Limit Violations; PRC-001-1 – System Protection Coordination; and PER-001-0 - Operating Personnel Responsibility and Authority.

Standard TOP-001-1 — Reliability Responsibilities and Authorities		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.	Deleted	This is a generic requirement that is no longer necessary since there are now specific requirements that cover all needed reliability actions. Deletion of this requirement doesn't alleviate responsibility for actions, as each individual requirement in the Reliability Standards now specifies an action and a responsible entity. These needed actions required for reliability of the bulk power System have been more clearly laid out in revised standards. (See FERC Order 693a, Paragraph 112.) The requirement is also non-specific, ambiguous, and not performance-oriented. If an entity doesn't perform as specified in an individual requirement, then they are held accountable at that level. All of this makes this requirement redundant. The overall reliability of the bulk power System is not adversely affected by the deletion of this requirement. In FERC Order 693a, Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives. The SDT believes that this same logic applies to Transmission Operators and Balancing Authorities, which makes this requirement superfluous; and, thus, it can be deleted.

		FERC Order 693a, Paragraph 112: "In response to Avista, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of reliability standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize Reliability Coordinators to issue directives. Under the voluntary reliability scheme in place prior to Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a Reliability Coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, we view these as vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
R2. Each Transmission Operator shall take immediate actions to alleviate operating emergencies, including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.	Proposed TOP-001-2, Requirement R11	Replaced by proposed TOP-001-2, R11: The undefined term 'operating emergencies' is no longer utilized, and the requirement has been made more stringent by not restricting Transmission Operator actions to that undefined condition. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant time frame. TOP-001-2, R11. Each Transmission Operator shall act or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued	Proposed IRO-001-3, Requirements R2, R3 & R4.	Replaced by: IRO-001-3, R2. Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent

by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.		identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-001-3, R3. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall comply with its Reliability Coordinator's direction per Requirement R2, unless the direction per Requirement R2 cannot be implemented or such actions would violate safety, equipment, regulatory or statutory requirements. IRO-001-3, R4. Each Transmission Operator, Balancing Authority, Generator Operator, Interchange Coordinator and Distribution Provider shall inform its Reliability Coordinator upon recognition of its inability to perform, as directed per Requirement R3.
R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load-Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.	Proposed TOP-001-2, Requirements R1 & R2	Replaced by proposed: TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each reliability directive issued and identified as such by its Transmission Operator(s), unless such actions would violate safety, equipment, regulatory, or statutory requirements. TOP-001-2, R2. Each Balancing Authority, Distribution Provider, Load-Serving Entity, and Generator Operator shall inform its Transmission Operator upon recognition of its inability to perform an identified reliability directive issued by that Transmission Operator.
R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate	Proposed TOP-001-2, Requirement R3 Proposed TOP-001-2, Requirement R11.	Replaced by proposed: TOP-001-2, R3. Each Transmission Operator shall inform its Reliability Coordinator and Transmission Operators that are known or expected to be affected by each actual and anticipated Emergency based on its assessment of its Operational Planning Analysis.

the emergency.		TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8. The inclusion of the T_v term adds clarity and tends to make the new requirement more stringent than the existing requirement by providing a relevant time frame.
R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.	Proposed TOP-001-2, Requirement R4 for the Transmission Operator. Approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 for the Balancing Authority	Replaced by proposed TOP-001-2, R4. TOP-001-2, R4. Each Transmission Operator shall render emergency assistance to other Transmission Operators, as requested and available, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The Generator Operator was deleted from this requirement since it can't be contacted directly by others and will only respond to such requests if they were in the form of a reliability directive from its Transmission Operator, which is covered in proposed TOP-001-2, Requirement R1. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. The approved EOP-001-0 and proposed EOP-001-2b, Requirement R1 covers the Balancing Authority. So to eliminate a redundancy, the Balancing Authority has been removed from this requirement. In addition, the Balancing Authority must still respond to any Reliability Directive from the Transmission Operator, as stated in proposed TOP-001-2, Requirement R1. EOP-001-2b, R1. Balancing Authorities shall have

		operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
R7. Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless: R7.1 - For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.2 - For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility. R7.3 - When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R5	R7: Replaced by proposed TOP-001-2, R5 for the Transmission Operator. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. R7 – The Generator Operator can't know if their actions will burden neighboring Systems, since they do not have reliability data. The Transmission Operator will know if the Generator Operator actions will burden neighboring Systems and is required to act on this information, as per proposed TOP-001-2, R5. R7.1 – Replaced by proposed TOP-001-2, R5 for both the Transmission Operator and the Generator Operator. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. R7.2 - Replaced by proposed TOP-001-2, R5 for the Transmission Operator. After-the-fact notifications have been replaced by the proposed TOP-003-2, R1 and approved IRO-010-1a, since those actions will now be seen through telemetry.

notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.		TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading Outages.
R8. During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance, it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.	Approved EOP-002-3, Requirement R6. Approved VAR-001-1, Requirement R8. Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirements R1, R8, and R12. Approved IRO-009-1, Requirements R1 and R2. Approved EOP-003-1, Requirement R1.	Real Power Balance and Reactive Power Balance are not defined terms. First sentence – Real Power: For the Balancing Authority part of the requirement, replaced by approved EOP-002-2.1, Requirement R6. The Transmission Operator does not balance Real Power so that part of the sentence can be deleted per the NERC Functional Model V5. First sentence – Reactive Power: Replaced by Approved VAR-001-1, Requirement R8 for the Transmission Operator, which covers Reactive Power requirements and the meaning of balancing Reactive Power for the Transmission Operator. The Balancing Authority must be told by the Transmission Operator to take actions regarding Reactive Power per the NERC Functional Model V5 (see proposed TOP-001-2, Requirement R1) and, therefore, the Balancing Authority can be deleted from this part of the requirement. Second sentence – The Balancing Authority must be told by the Transmission Operator to take actions regarding

		Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, the Balancing Authority is not necessary. Replaced by approved VAR-001-1, Requirements R1, R8, and R12 for the Transmission Operator. Third sentence – Replaced by approved IRO-009-1, Requirements R1 and R2 for the Reliability Coordinator. Replaced by approved EOP-003-1, Requirement R1 for the Transmission Operator and Balancing Authority. EOP-002-3, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. VAR-001-1 R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. VAR-001-1, R8. Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, Load shedding – to maintain System and Interconnection voltages within established limits. VAR-001-1, R12. The Transmission Operator shall direct corrective action, including Load reduction necessary to prevent voltage collapse when reactive resources are insufficient. TOP-001-2, R1. Each Balancing Authority, Generator

		Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. IRO-009-1, R1. For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more operating processes, procedures, or plans that identify actions it shall take, or actions it shall direct others to take (up to and including Load shedding) that can be implemented in time to prevent exceeding those IROLs. IRO-009-1, R2.For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more operating processes, procedures, or plans that identify actions it shall take, or actions it shall direct others to take (up to and including Load shedding) to mitigate the magnitude and duration of exceeding that IROL such that the IROL is relieved within the IROL's Tv. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load rather than risk an uncontrolled failure of components or Cascading Outages of the Interconnection.
Standard TOP-002-2a — Normal Operations Planning		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Balancing Authority and Transmission Operator shall maintain a set of current plans that are designed to evaluate options and set procedures for	Approved BAL-001-0.1a. Approved BAL-002-1.	First sentence – Deleted for Balancing Authority, retained for Transmission Operator. The Balancing Authority is required to balance by approved BAL-001-0.1a and approved BAL-002-1 and

reliable operation through a reasonable future time period. In addition, each Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.	Approved EOP-002-2.1, Requirement R6. Proposed TOP-002-3, Requirements R1 through R3.	must take action, per approved EOP-002-2.1, Requirement R6 and, thus, the Balancing Authority part of this sentence can be deleted. Retained for Transmission Operator and moved to proposed TOP-002-3, Requirements R1 through R3. This is patterned after the approved IRO-008-1, Requirement R1 for the Reliability Coordinator. Second sentence – Deleted as superfluous. Use of appropriate personnel and equipment is incumbent to responsible entities, as per their certification as NERC registered entities. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing Real Power demand and supply in Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of Load, and because Contingency Reserve activation does not typically apply to the loss of Load, the application of DCS is limited to the loss of supply, and does not apply to the loss of Load. EOP-002-2.1, R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. TOP-002-3, R1: Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.

		TOP-002-3, R2: Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability internal to its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1. TOP-002-3, R3: Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R2. Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.	Deleted	The SDT reviewed the purpose of the Reliability Standard and believes that this requirement referred to operations planning. Given the current definition of Transmission Operator in the Glossary and Functional Model v5, operations planning is part of what the Transmission Operator is required to do and, as such, this requirement is no longer needed and can be deleted. Functional Model V5: Transmission Operator: The entity responsible for the reliability of its "local" transmission System, and that operates or directs the operations of the transmission Facilities.
R3. Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.	Proposed TOP-003-2. Approved MOD-001-1a, Requirements R1 & R2. Approved MOD-030-2, Requirement R3.	For all but the Transmission Service Provider, moved to proposed TOP-003-2 requires the transfer of any and all required data, regardless of time frame involved. The Transmission Service Provider provisions are already covered in: • Approved MOD-001-1a, Requirement R1: Transmission Operators select transfer capability methodology from approved MOD-028, -029, or -030. • Approved MOD-030-2, Requirement R3: Transmission Operator gives transmission model updated at least once per day to Transmission Service Provider.

		• Approved MOD-001-1a, Requirement R2: Transmission Service Providers use the methodology designated in approved MOD-001-1a, Requirement R1 by the Transmission Operator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. MOD-001-1a, R1. Each Transmission Operator shall select one of the methodologies listed below for calculating Available Transfer Capability (ATC) or Available Flowgate Capability (AFC) for each ATC Path per time period identified in R2 for those Facilities within its Transmission operating area. MOD-030-2, R3. The Transmission Operator shall make available to the Transmission Service Provider a Transmission model to determine Available Flowgate Capability (AFC) that meets the following criteria: [LA1]MOD-001-1a, R2. Each Transmission Service Provider shall calculate ATC or AFC values, as listed below, using[LA2] the methodology or methodologies selected by its Transmission Operator(s).
R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator so that normal Interconnection operation will proceed in an orderly and consistent manner.	Proposed TOP-003-2, Requirement R5. Approved IRO-010-1a, Requirement R3.	Proposed TOP-003-2 requires the transfer of any and all required data between and amongst Balancing Authorities and Transmission Operators, regardless of the time frame involved. Data requirements for Reliability Coordinators are covered in approved IRO-010-1a, Requirement R3 making this requirement redundant for Reliability Coordinators, so the Reliability Coordinator has been removed here. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

		specifications for data. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R5. Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.	Approved BAL-001-0.1a. Proposed TOP-003-2, Requirement R4. Proposed TOP-002-3, Requirement R1.	The part of the requirement dealing with the Balancing Authority is replaced by approved BAL-001-0.1a. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built into the Functional Model. Therefore, the Transmission Operator should be developing the plan and passing it down to the Balancing Authority. The Balancing Authority provides any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R5. The part of the requirement dealing with the Transmission Operator has been moved to proposed TOP-002-3, Requirement R1. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing Real Power demand and supply in Real-time. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

		specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R6. Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in System configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.	Approved BAL-002-1, Requirements R2 – R4. Proposed TOP-003-2, Requirement R5. Proposed TOP-002-3, Requirement R1	The part of this requirement dealing with the Balancing Authority is replaced by approved BAL-002-1, Requirements R2 through R4 and approved EOP-002-2.1 and the proposed EOP-002-3, Requirement R6. The Functional Model requires a Balancing Authority to operate under the direction of the Transmission Operator for such matters. It is also a basic tenet of operations and good standards that only one entity should be 'in charge'. The Balancing Authority can only work within the constraints handed down by the Transmission Operator. Any needed coordination issues are built in to the Functional Model. Therefore, the Transmission Operator should be doing the plan and passing it down to the Balancing Authority. The Balancing Authority gets any needed data to the Transmission Operator through the data specification requirements in proposed TOP-003-2, Requirement R4. The part of the requirement dealing with the Transmission Operator - replaced by proposed TOP-002-3, Requirement R1. The n-1 contingency planning is 'built in' to the Operational Planning Analysis since SOLs are derived according to FAC-010-2.1, FAC-011-2, and FAC-014-2 which includes contingency planning. The SDT does not believe that there is a need for the last part of the sentence 'in accordance with…' with the advent of the ERO and enforceable reliability standards.

		As stated in the NERC Functional Model V5: " the Balancing Authority's mission is to maintain the balance between Loads and resources in Real-time within its Balancing Authority Area by keeping its actual Interchange equal to its scheduled Interchange and meeting its frequency bias obligation." To this end and in accordance with approved NERC Reliability Standards BAL-001-0.1a and approved BAL-002-1), Balancing Authorities are required to meet all control performance and disturbance recovery criteria for any System condition. Balancing Authorities are not responsible for the operation of the transmission System. The Transmission Operator is responsible for the Real-time operating reliability of the transmission assets under its purview and, as such, has the authority to issue reliability-related directives to entities within its Transmission Operator Area. Balancing Authorities are required to implement directives received from the Transmission Operator or the Reliability Coordinator regarding Load, generation and Interchange for transmission concerns both predicted (e.g., through Unit Commitment) and actual (e.g., through re-dispatch, Interchange modifications or Load shedding). If the Balancing Authorities' actions do not resolve the transmission issues, it is the Transmission Operators' or Reliability Coordinators' responsibility to direct alternative actions. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: BAL-002-1, R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS. BAL-002-1, R4. Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator,

		Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. FAC-010-2.1, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable planning of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-011-2, Purpose: To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. FAC-014-2, Purpose. To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. BAL-001-0.1a, Purpose: To maintain Interconnection steady-state frequency within defined limits by balancing Real Power demand and supply in Real-time. BAL-002-1, Purpose: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of Load and because Contingency

		Reserve activation does not typically apply to the loss of Load, the application of DCS is limited to the loss of supply and does not apply to the loss of Load.
R7. Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.	Approved BAL-002-1, Requirement R2. Proposed TOP-002-3, Requirement R1.	The Balancing Authority is required to always plan to meet and recover from Contingency events, as stated in approved BAL-002-1, Requirement R2 and, therefore, this requirement is redundant and can be deleted, as all elements of the requirement are now covered in other standards. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and are replaced by proposed TOP-002-3, Requirement R1. Operational Planning Analysis includes deliverability considerations, since any deliverability problems will appear as limit violations in the analysis. BAL-002-1, R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including: TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R8. Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.	Proposed TOP-001-2, Requirement R1. Approved VAR-001-1, Requirement R1. Proposed TOP-002-3, Requirement R1	The Balancing Authority must be told by the Transmission Operator to take actions regarding Reactive Power (see proposed TOP-001-2, Requirement R1) and, thus, this requirement can be deleted, as all elements of the requirement are now covered in other standards. Voltage and Reactive Power balance are the responsibility of the Transmission Operator and are replaced by approved VAR-001-1, Requirement R1. Deliverability is not in the control of the Balancing Authority; it is a Transmission Operator responsibility and is replaced by proposed TOP-002-3, Requirement

		R1 since any deliverability problems will appear as limit violations in the analysis. TOP-001-2, R1. Each Balancing Authority, Generator Operator, Distribution Provider, and Load-Serving Entity shall comply with each identified Reliability Directive issued and identified as such by its Transmission Operator, unless such actions would violate safety, equipment, regulatory, or statutory requirements. VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions.
R9. Each Balancing Authority shall plan to meet Interchange Schedules and ramps.	Approved INT-003-2, Requirement R1.	Replaced by approved INT-003-2, R1. INT-003-2, R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.
R10. Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).	Deleted for Balancing Authority. Proposed TOP-002-3, Requirements R1 & R2.	Balancing Authority - The Balancing Authority is only responsible to respond to Reliability Directives as per the definition of Balancing Authority in the NERC Glossary, and, thus, this requirement should never have been applicable to the Balancing Authority. SOLs and IROLs are limits for which the Balancing Authority may not have (and is not required to have) the ability to monitor or control. The Transmission Operator, who is required to monitor SOLs, instructs the Balancing Authority as to what to do in these situations.

		As stated in the NERC Functional Model V5, "the Balancing Authority's mission is to maintain the balance between Loads and resources in Real-time within its Balancing Authority Area by keeping its actual Interchange equal to its scheduled Interchange and meeting its frequency bias obligation". The Balancing Authority does not possess the bulk power System information necessary to manage Transmission flows. Therefore, the Balancing Authority can only plan to meet SOLs and IROLs by responding to directions from the Transmission Operator, including scheduling and operating resources within the limits prescribed by the Transmission Operator. Transmission Operator – replaced by proposed TOP-002-3, Requirement R1 (analysis of SOLs) & Requirement R2 (avoid IROLs). TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions that will allow it to assess whether the planned operations for the next day within its Transmission Operator Area will exceed any of its Facility Ratings or Stability Limits during anticipated normal and Contingency event conditions. TOP-002-3, R2. Each Transmission Operator shall plan to operate within each Interconnection Reliability Operating Limit (IROL) and each System Operating Limit (SOL) which, while not an IROL, has been identified by the Transmission Operator as supporting reliability in its Transmission Operator Area, identified as a result of the Operational Planning Analysis performed in Requirement R1.
R11. The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall	Approved FAC-011-2. Approved FAC-014-2.	First sentence – Replaced by FAC-011-2 and FAC-014-2 where SOLs are determined. FAC-011-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.	Proposed TOP-002-3, Requirements R1 & R3.	FAC-014-2: Purpose - To ensure that System Operating Limits (SOLs) used in the reliable planning and operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies. Second sentence – Replaced by approved FAC-014-2, R2 & R5.1. FAC-014-2, R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2, R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. Third sentence – Replaced by proposed TOP-002-3. 'update… as necessary' is ambiguous and the SDT believes that proposed TOP-002-3 is a better solution. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-002-3, R3. Each Transmission Operator shall notify all NERC registered entities identified in the plan(s) cited in Requirement R2 as to their role in those plan(s).
R12. The Transmission Service Provider shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional Total	Approved MOD-028-1, Requirement R6.1. Approved MOD-029-1a, Requirement R3. Approved MOD-	Replaced by approved MOD-028-1, Requirement R6.1, MOD-029-1a, Requirement R3, and MOD-030-2, Requirement R2.4. Because IROLs by definition are a subset of SOLs, IROLs are included.

Transfer Capability and Available Transfer Capability calculation processes.	30-2 Requirement R2.4.	MOD-028-1, R6.1,Determine the incremental Transfer Capability for each ATC Path by increasing generation and/or decreasing Load within the source Balancing Authority area and decreasing generation and/or increasing Load within the sink Balancing Authority area until either: A System Operating Limit is reached on the Transmission Service Provider's System, or A SOL is reached on any other adjacent System in the Transmission model that is not on the study path and the distribution factor is 5% or greater. MOD-029-1a, R3, Each Transmission Operator shall establish the TTC at the lesser of the value calculated in R2 or any System Operating Limit (SOL) for that ATC Path. MOD-030-2, R2.4, Establish the TFC of each of the defined Flowgates as equal to: For thermal limits, the System Operating Limit (SOL) of the Flowgate. For voltage or stability limits, the flow that will respect the SOL of the Flowgate.
R13. At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the Balancing Authority or Transmission Operator operating personnel as requested.	Proposed MOD-25-2, Requirement R1 Proposed TOP-003-2, Requirement R5	Replaced by proposed MOD-025-2, R1. MOD-025-2, R1: Each Generator Owner shall: 1.1. Verify the Real and Reactive Power capability of its generating units and shall verify the Reactive Power capability of its synchronous condenser units in accordance with Attachment 1. 1.2. Record the information on Attachment 2 (or on the Generator Owner's form that contains the same information as Attachment 2); 1.3. Submit within 90 calendar days of the date the

		data is recorded to its Transmission Planner. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R14. Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics; including but not limited to: 14.1 - Changes in real and reactive output capabilities. (Retired August 1, 2007) 14.2 - Changes in real output capabilities. (Effective August 1, 2007) 14.3 - Automatic Voltage Regulator status and mode setting. (Retired August 1, 2007)	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R15. Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R16. Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to: 16.1	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.

- Changes in transmission facility status. 16.2 - Changes in transmission facility rating		
R17. Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.	Approved IRO-010-1a, Requirement R3	Replaced by approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R18. Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.	Deleted	This requirement adds no reliability benefit. Entities have existing processes that handle this issue. There has never been a documented case of the lack of uniform line identifiers contributing to a System reliability issue. This is an administrative item, as seen in the measure, which simply requires a list of line identifiers. The true reliability issue is not the name of a line but what is happening to it, pointing out the difficulty in assigning compliance responsibility for such a requirement, as well as the near impossibility of coming up with truly unique identifiers on a nation-wide basis. The bottom line is that this situation is handled by the operators as part of their normal responsibilities, and no one is aware of a switching error caused by confusion over line identifiers.
R19. Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.	Deleted	This is part of an entity's certification and is no longer required in standards. Furthermore, accuracy is a relative term that would be difficult to measure and assess compliance with. What is accurate? All calculated line flows are within 5% of actual flows? What if 14,999 lines out of 15,000 had calculated line flows within 5% and the 15,000th had a 6% error? Do we now call the model inaccurate and not rely on the results? How do you define actual flows when meters have accuracy errors, as well (i.e., no perfect meter exists)?
Standard TOP-003-1 — Planned Outage Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment

R1. Generator Operators and Transmission Operators shall provide planned outage information. 1.1 - Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements. 1.2 - Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements. 1.3 - Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.	Proposed TOP-003-2, Requirements R1 & R2	Replaced by proposed TOP-003-2, Requirements R1 & R2. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring.
R2. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on	Proposed TOP-001-2, Requirement R5 Proposed TOP-003-2, Requirement R1 Proposed TOP-003-	Replaced by: proposed TOP-001-2, Requirement R5 which requires the Transmission Operator to coordinate actions while proposed TOP-003-2, Requirement R1 requires the Transmission Operator to identify the data it needs from the Balancing Authority to coordinate outages of voltage regulation equipment. Further, proposed TOP-003-2,

generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., among affected Balancing Authorities and Transmission Operators, as required.	2, Requirement R5	Requirement R5 requires the Balancing Authority to provide the data to the Transmission Operator that the Transmission Operator identified it needs. TOP-001-2, R5: Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations, known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-003-2, R1: Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R5: Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Operator, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.	Proposed TOP-001-2, Requirement R6	Moved to proposed TOP-001-2, Requirement R6 TOP-001-2, R6. Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator and negatively impacted interconnected NERC-registered entities of planned outages of telemetering equipment, control equipment and associated communication channels between the affected entities.
R4. Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.	Proposed IRO-001-3, R2 Proposed IRO-005-4, R1	Moved to the proposed IRO-001-3, Requirements R3 and proposed IRO-005-4, Requirement R1 which gives the Reliability Coordinator the authority to resolve the conflict. IRO-001-3, R2: Each Reliability Coordinator shall take actions or direct actions, which could include issuing Reliability

		Directives, of Transmission Operators, Balancing Authorities, Generator Operators, Interchange Coordinators and Distribution Providers within its Reliability Coordinator Area to prevent identified events or mitigate the magnitude or duration of actual events that result in Adverse Reliability Impacts. IRO-005-4, R1: When the results of an Operational Planning Analysis or Real-time Assessment indicate an anticipated or actual condition with Adverse Reliability Impacts within its Reliability Coordinator Area, each Reliability Coordinator shall notify all impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area.
Standard TOP-004-2 — Transmission Operations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R2. Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.	Proposed TOP-001-2, Requirements R7and R9	Moved to proposed TOP-001-2, Requirements R7and R9. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL)

		identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R3. Each Transmission Operator shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its Reliability Coordinator.	Proposed TOP-001-2, Requirements R7 and R9	Moved to proposed TOP-001-2, Requirements R7 and R9. These requirements are not limited by single or multiple Contingencies, but are based solely on identified IROLs (and selected SOLs), regardless of how they were identified or whether they were identified by the Transmission Operator or Reliability Coordinator. FAC-011-02 and FAC-014-2 work collectively to establish how multiple Contingencies are considered in IROLs and SOLs. FAC-014-2, R6 requires the Planning Coordinator to identify the subset of multiple Contingencies from TPL-003 which result in stability limits and to provide this list to the Reliability Coordinators. FAC-011-2, R3.3 requires the Reliability Coordinator to include in their SOL methodology a process for determining which of the stability limits associated with multiple Contingencies are used to establish SOLs. FAC-014-2, R1 requires the Reliability Coordinator to determine which subset of SOLs qualify as IROLS. FAC-014-2, R1 requires the Reliability Coordinator to ensure SOLs, including IROLs, are established for its Reliability Coordinator Area, while FAC-014-2, R2 also requires the TOP to establish SOLs for its area. Thus, IROLs and SOLs that consider multiple outages will be developed appropriately and the Transmission Operator will operate to them. FAC-011-2, R1, The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall: R1.3. Include a description of how to identify the subset of SOLs that qualify as IROLs.

		FAC-011-2, R3, The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each: R3.3. A process for determining which of the stability limits associated with the list of multiple Contingencies (provided by the Planning Authority in accordance with FAC-014 Requirement 6) are applicable for use in the operating horizon, given the actual or expected System conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple Contingencies. FAC-014-2, R1, The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology. FAC-014-2, R2, The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology. FAC-014-2 R6, The Planning Authority shall identify the subset of multiple Contingencies (if any), from Reliability Standard TPL-003 which result in stability limits. R6.1. The Planning Authority shall provide this list of multiple Contingencies and the associated stability limits to the Reliability Coordinators that monitor the Facilities associated with these Contingencies and limits. R6.2. If the Planning Authority does not identify any stability-related multiple Contingencies, the

		Planning Authority shall so notify the Reliability Coordinator. TOP-001-2, R7: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9: Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based.
R4. If a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.	Proposed TOP-001-2, Requirements R7 and R9 Approved EOP-006-2	The SDT has determined a better way to handle such a situation is to treat it like an IROL or restoration scenario, and to take the same type of actions that you would apply for alleviating those situations. Therefore, it is replaced by proposed TOP-001-2, Requirements R7 and R9 and the approved EOP-006-2. This allows the operator sufficient flexibility within a structured environment to take the necessary actions for the reliability of the bulk power System. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. EOP-006-2, Purpose: Ensure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
R5. Each Transmission Operator shall make every effort to remain connected to the	Deleted	Normally, the Transmission Operator does not have the right to unilaterally separate – that can only be done through the authorization of the Reliability

Interconnection. If the Transmission Operator determines that by remaining interconnected it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.		Coordinator, unless failure to act immediately would violate safety, equipment, or regulatory or statutory requirements, thus this requirement is a moot point under the Functional Model definitions and can be deleted.
R6. Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including: 6.1 - Monitoring and controlling voltage levels and real and reactive power flows. 6.2 - Switching transmission elements. 6.3 - Planned outages of transmission elements. 6.4 - Responding to IROL and SOL violations.	Proposed TOP-001-2 Approved VAR-001-1, Requirement R1 Proposed TOP-001-2, Requirements R7 and R9 ProposedTOP-001-2, Requirement R5 Proposed TOP-001-2, Requirement R11	The first sentence has been superseded by the NERC Reliability Standards, taken as a whole. Examples of such would be the proposed TOP-001-2. The second sentence was replaced as follows: R6.1 is duplicative of approved VAR-001-1, Requirement R1 for Reactive. Real Power flows are covered in proposed TOP-001-2, Requirements R7 and R9. R6.2 is covered in proposed TOP-001-2, Requirement R5. R6.3 – moved to proposedTOP-001-2, Requirement R5. R6.4 – moved to proposed TOP-001-2, Requirement R11. TOP-001-2, Purpose: To prevent instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Interconnection by ensuring prompt action to prevent or mitigate such occurrences VAR-001-1, R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and Mvar flows within their individual areas and with the areas of neighboring Transmission Operators.

		TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. TOP-001-2, R5. Each Transmission Operator shall inform its Reliability Coordinator and other Transmission Operators of its operations known or expected to result in an Adverse Reliability Impact on those respective Transmission Operator Areas, unless conditions do not permit such communications. Such operations may include relay or equipment failures and changes in generation, Transmission, or Load. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard TOP-005-2 — Operational Reliability Information		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area. 1.1 - Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 "Electric System Reliability Data" and any	Approved IRO-010-1a, Requirement R3	Moved to approved IRO-010-1a, Requirement R3. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.

additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.		
R2. As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for "Electric System Reliability Data."	Deleted	Confidentiality is not a reliability issue, but a market or business issue. Since this is not a reliability issue, it does not belong in the Reliability Standards and can be deleted.
R3. Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 "Electric System Reliability Data," unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.	Proposed TOP-003-2, Requirement R5	Replaced by proposed TOP-003-2, Requirement R5. TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R4. Each Purchasing-Selling Entity shall provide information, as requested by its Host Balancing Authorities and Transmission Operators, to enable them to conduct operational reliability assessments and coordinate reliable operations.	Deleted	Deleted as redundant to NAESB standard –All operating data that a Purchasing Selling Entity has, that a Transmission Operator or Balancing Authority needs is part of eTag and is acquired through that system.

Standard TOP-006-2 – Monitoring System Conditions		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use. 1.1 - Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use. 1.2 - Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	R1 & R1.1 are replaced by proposed TOP-003-2, Requirement R1. R1.2 – replaced by approved IRO-010-1a, Requirement R3. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. IRO-010-1a, R3. Each Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-serving Entity, Reliability Coordinator, Transmission Operator, and Transmission Owner shall provide data and information, as specified, to the Reliability Coordinator(s) with which it has a reliability relationship.
R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3. Approved BAL-005-0.1b. Proposed TOP-001-2, Requirement R10. Approved IRO-008-1, Requirement R2.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-

		time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading outages. The act of monitoring is un-measureable. Entities will be in violation of other standards if they don't perform adequate monitoring. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs, and approved IRO-008-1, Requirement R2 for Real-time assessments every 30 minutes for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring.

		TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading outages.
R4. Each Transmission Operator and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.	Proposed TOP-003-2, Requirements R1 & R2 Approved IRO-010-1a, Requirement R3.	Replaced by proposed TOP-003-2, Requirement R1 for the Transmission Operator & R2 for Balancing Authority. Replaced by approved IRO-010-1a, Requirement R1 for the Reliability Coordinator. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-003-2, R2. Each Balancing Authority shall create a documented specification for the data necessary for it to perform its analysis functions and required Real-time monitoring. IRO-010-1a, R1. The Reliability Coordinator shall have a documented specification for data and information to build and maintain models to support Real-time monitoring, Operational Planning Analyses, and Real-time Assessments of its Reliability Coordinator Area to prevent instability, uncontrolled separation, and Cascading outages.
R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to	Deleted	Deleted as this is covered in the certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R10 for Transmission Operator avoiding IROLs; approved IRO-008-1, Requirement R2

indicate, if appropriate, the need for corrective action.		for Real-time assessments every 30 minutes for Reliability Coordinators BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded. IRO-008-1, R1. Each Reliability Coordinator shall perform a Real-Time Assessment at least once every 30 minutes to determine if its Wide Area is exceeding any IROLs or is expected to exceed any IROLs.
R6. Each Balancing Authority and Transmission Operator shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); proposed TOP-001-2, Requirement R7 for Transmission Operator avoiding IROLs. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v.

R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.	Deleted	Deleted – covered in certification process for initial core capabilities. Entities will be in violation of other standards if they don't maintain their initial certification. For example, approved BAL-005-0.1b for ACE calculations (Balancing Authority); approved EOP-003-1, Requirement R2 for Transmission Operator avoiding underfrequency; approved EOP-006-2, Requirement R8 for resynchronization for Reliability Coordinators. BAL-005-01b, Purpose: This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all Facilities and Load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved. EOP-003-1, R2. Each Transmission Operator and Balancing Authority shall establish plans for automatic Load shedding for underfrequency or undervoltage conditions. EOP-006-2, R8. The Reliability Coordinator shall coordinate or authorize resynchronizing islanded areas that bridge boundaries between Transmission Operators or Reliability Coordinators. If the resynchronization cannot be completed as expected the Reliability Coordinator shall utilize its restoration plan strategies to facilitate resynchronization.
Standard TOP-007-0 - Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded, and the actions being taken to return the system to within limits.	Proposed TOP-001-2, Requirement R10	Moved to proposed TOP-001-2, Requirement R10. TOP-001-2, R10. Each Transmission Operator shall inform its Reliability Coordinator of its actions to return the System to within limits when an IROL, or an SOL identified in Requirement R8, has been exceeded.

R2. Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.	Proposed TOP-001-2, Requirement R11	Moved to proposed TOP-001-2, Requirement R11. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
R3. A Transmission Operator shall take all appropriate actions, up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.	Approved EOP-003-1, Requirements R1 and in proposed EOP-003-2, Requirement R1	Replaced by approved EOP-003-1, Requirements R1. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load rather than risk an uncontrolled failure of components or Cascading outages of the Interconnection.
R4. The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.	Approved IRO-008-1, Requirement R3	Replaced by approved IRO-008-1, Requirement R3. IRO-008-1, R3. When a Reliability Coordinator determines that the results of an Operational Planning Analysis or Real-Time Assessment indicates the need for specific operational actions to prevent or mitigate an instance of exceeding an IROL, the Reliability Coordinator shall share its results with those entities that are expected to take those actions.
Standard TOP-008-1 - Response to Transmission Limit Violations		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.	Approved EOP-003-1, Requirements R1 and in proposed EOP-003-2, Requirement R1 Proposed TOP-001-2, Requirement R11	Replaced by approved EOP-003-1, Requirements R1 and proposed TOP-001-2, Requirement R11. EOP-003-1, R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer Load, rather than risk an uncontrolled failure of components or Cascading Outages of the Interconnection. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement

		R8.
R2. Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.	Proposed TOP-001-2, Requirements R7 and R9 Approved IRO-009-1, Requirement R5	First sentence – Replaced by proposed TOP-001-2, Requirements R7 and R9. Second sentence – Replaced by approved IRO-009-1, Requirement R5 for the Reliability Coordinator who is now responsible for such matters. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R9. Each Transmission Operator shall not operate outside any System Operating Limit (SOL) identified in Requirement R8 for a continuous duration that would cause a violation of the Facility Rating or Stability criteria upon which it is based. IRO-009-1, R5. If unanimity cannot be reached on the value for an IROL or its Tv, each Reliability Coordinator that monitors that Facility (or group of Facilities) shall, without delay, use the most conservative of the values (the value with the least impact on reliability) under consideration.
R3. The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.	Deleted	Placing this procedure in a requirement when it is only one of the possible options for alleviating the condition is bad practice and should not be mandated in standards. A standard should not be mandating disconnection. This is in conflict with other reliability standards where disconnection is dependent on System conditions and coordination with other functional entities. Such actions, taken unilaterally, could make conditions worse.
R4. The Transmission Operator shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted	Proposed TOP-003-2, Requirement R1 Proposed TOP-002-3, Requirement R1	Data piece is replaced by proposed TOP-003-2, Requirement R1. Analysis tools are covered in the certification process for core capabilities and, therefore, are not needed

in all operating timeframes. The Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.	Proposed TOP-001-2, Requirement R7 Proposed TOP-001-2, Requirement R11	here. The Transmission Operator will be in violation of other standards if they don't maintain their initial certification. For example, they can't develop their limits without maintaining their tools. Replaced by proposed TOP-002-3, Requirement R1 for analysis. Replaced by proposed TOP-001-2, Requirement R7 for real-time analysis required for IROL mitigation. Proposed TOP-001-2, Requirement R11 covers mitigation of limit violations. TOP-003-2, R1. Each Transmission Operator shall create a documented specification for the data necessary for it to perform its required Operational Planning Analyses and Real-time monitoring. TOP-002-3, R1. Each Transmission Operator shall have an Operational Planning Analysis that represents projected System conditions. TOP-001-2, R7. Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_v. TOP-001-2, R11. Each Transmission Operator shall act, or direct others to act, to mitigate both the magnitude and duration of exceeding an IROL within the IROL's T_v, or of an SOL identified in Requirement R8.
Standard PER-001-0 - Operating Personnel Responsibility and Authority		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable	Deleted	In FERC Order 693a, Paragraph 112, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of reliability standards that mandate compliance with such directives. The SDT reasonably applied this same logic to Transmission Operators and

operation of the Bulk Electric System.		Balancing Authorities and that makes this requirement superfluous and, thus, it can be deleted. FERC Order 693a, Paragraph 112: In response to Avista, the Commission clarifies that a Reliability Coordinator's authority to issue directives arises out of the Commission's approval of reliability standards that mandate compliance with such directives. Avista is correct that contracts are unnecessary to authorize reliability coordinators to issue directives. Under the voluntary reliability scheme in place prior to Section 215 of the FPA, a contractual basis was needed to assure that entities would comply with a Reliability Coordinator's directive. Pursuant to the current, mandatory reliability scheme established by statute, contracts are no longer needed. We view the concerns raised by Avista as part of the transition from a voluntary to mandatory scheme. Although, as noted by Avisa, IRO-001-1 retains references to contracts, these are vestiges of an earlier program that no longer control, given the current, mandatory mechanism.
Standard PRC-001-1 – System Protection Coordination		
Requirement in Approved Standard	Translation to New Standard or Other Action	Proposed Language in New Standard or Comment
R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.
R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others: R5.1. Each Generator Operator	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented

shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems. R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.		specifications for data.
R6. Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.	Proposed TOP-003-2, Requirement R5.	Moved to proposed TOP-003-2, R5: TOP-003-2, R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Interchange Authority, Load-Serving Entity, Transmission Owner, and Distribution Provider receiving a data specification in Requirement R3 or R4 shall satisfy the obligations of the documented specifications for data.